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

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O R D E R

INTRODUCTION

On June 19, 2001, Governor Paul E. Patton issued Executive Order 2001-771, which, among other things, established a 180-day moratorium on the Commission's acceptance of applications for authorization to construct new electric power plants in the Commonwealth or for declarations that such authorization is not needed. That Executive Order also directed the Commission to review and study issues relating to the need for and development of new electric generating capacity in the Commonwealth, including, but not limited to, the impact on the electric supply grid, facility siting issues, and economic development matters, with the goal of ensuring a continued, reliable source of supply of electricity for the citizens of the Commonwealth and the continued environmental and economic vitality of the Commonwealth and its communities.

In response to that Executive Order, the Commission initiated this proceeding by Order dated July 2, 2001, and identified therein the following issues to be reviewed: (1) the appropriate level of reliance on purchased power, (2) the appropriate reserve margins to meet existing and future electric demand, (3) the impact of spikes in natural gas prices on electric utility planning strategies, and (4) the adequacy of Kentucky's electric transmission facilities. In recognition that the Commission's jurisdiction does not extend to electric systems owned by cities or supplied by the Tennessee Valley Authority ("TVA"), the statistics, findings, and conclusions herein are limited to jurisdictional utilities, unless otherwise noted.

PROCEDURAL BACKGROUND

The Commonwealth's four jurisdictional electric generating utilities, Kentucky Power Company d/b/a American Electric Power ("AEP-KY"), East Kentucky Power Cooperative, Inc. ("East Kentucky"), Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU"), along with the state's two other major jurisdictional electric suppliers, Big Rivers Electric Corporation ("Big Rivers") and The Union Light, Heat and Power Company ("ULH&P"), were made parties to this proceeding. Also invited to intervene and participate in this review were the electric utilities that are not subject to Commission jurisdiction. Those non-jurisdictional utilities include Kentucky's municipal electric systems, TVA, TVA distribution cooperatives serving Kentucky, and independent power producers.

Intervening in this proceeding were the Attorney General of the Commonwealth of Kentucky ("AG"), Kentucky Industrial Utility Customers, Inc., Kentucky Division of Energy of the Natural Resources and Environmental Protection Cabinet ("Division of Energy"), Owensboro Municipal Utilities ("Owensboro Municipal"), the Municipal Electric Power Association of Kentucky ("MEPAK"), Kenergy Corporation ("Kenergy"), Thoroughbred Generating Company ("Thoroughbred Generating"), Gallatin Steel, North American Stainless, EnviroPower LLC, and residential consumer Robert L. Madison. Although TVA did not intervene, it filed statistical information and a post-hearing statement. Other participants at the invitation of the Commission were the Kentucky Population Research and Kentucky State Data Center at the University of Louisville ("State Data Center"), the Kentucky Cabinet for Economic Development, the Kentucky Commission for the New Economy, and the Governor's Office of Technology (collectively "Invited Parties").[1]

The utilities designated as parties to this proceeding filed written testimony and responded to two requests for information. Intervenors were afforded the opportunity to file testimony and to cross-examine witnesses. Three public hearings were held at the Commission's offices in Frankfort, Kentucky. The first hearing, held on August 13, 2001, was for the purpose of receiving testimony from, and cross-examining, representatives of the Invited Parties. The second hearing, on September 19, 2001, was to cross-examine the utilities' witnesses, and the third hearing, on October 1, 2001, was to cross-examine the intervenors' witnesses. Responses to hearing data requests have been received and post-hearing briefs were filed October 22, 2001.

[1] A list of witnesses is included in Appendix A to this Order.

EXECUTIVE SUMMARY

At the outset, the Commission expresses its thanks to the non-jurisdictional parties that intervened in this proceeding, and to TVA, which did not intervene but provided information. We would like to especially thank the individuals invited to present testimony at our first public hearing in August 2001: Ron Crouch of the Kentucky State Data Center; J.R. Wilhite of the Kentucky Cabinet for Economic Development; Bill Brundage, Ph.D., Commissioner for the New Economy; and Steve Dooley of the Governor's Office of Technology.

The Commission was directed to study the need for and development of new generation and transmission. The Kentucky State Energy Policy Advisory Board ("Energy Board") was charged with planning and developing a statewide energy policy. The charge to the Commission and, to a lesser extent, the Energy Board's charge are both reflected in this Order, which highlights major changes that have occurred in the electric industry in recent years that have impacted Kentucky.[2]

Changes impacting Kentucky include The Energy Policy Act of 1992, the Federal Energy Regulatory Commission's ("FERC") Order 888, retail restructuring in many states, FERC Order 2000, and stricter environmental regulations. They have resulted in utilities investing in peaking generation, with its low capital costs compared to base load

[2] A glossary of electric industry terminology and acronyms is included in Appendix I to this Order.

generation, and relying more on wholesale purchases. Utility reserve margins have been reduced from 20 percent to levels of 11 to 15 percent.

Kentucky has low electric rates, 12 percent below the regional average and 23 percent below the national average in 2000. These low rates are largely due to our reliance on coal-fired generation sold at cost-based rates as well as sound utility management, excellent public policy adopted by the General Assembly, and reasonable regulatory oversight. While electric restructuring does not appear likely here, results elsewhere show that the impacts of restructuring do not end at state borders. We want to maintain Kentucky's rate advantage, even in the face of restructuring adopted in nearby states, such as Ohio, where affiliates of some of our utilities are transferring generation to non-regulated affiliates that will sell power at market-based rates. These actions could potentially increase the price of electricity regionally if market-based rates exceed cost-based rates. We note that the Commonwealth of Kentucky benefits from having some of the lowest electric rates in the nation and it is in the best interests of the Commonwealth and its citizens to maintain these low electric rates into the future.

Six major electric utilities are regulated by the Commission. Two, East Kentucky and Big Rivers, are not-for-profit generation and transmission cooperatives. Two others, LG&E and KU, are in-state investor-owned utilities ("IOU"). The other two utilities, AEP-KY and ULH&P, are investor-owned utilities that are part of multi-state holding companies. In addition, the Commission regulates 55 other electric systems, including 20 distribution cooperatives and one private distributor. The Commission does not regulate the state's 29 municipal systems, 5 TVA-supplied cooperatives, and TVA.

Generation Issues

We reviewed the demand forecasting and supply planning of the major utilities. In 1991 the six major utilities had roughly 11,000 MW of installed or contractual capacity available with over 95 percent of the installed capacity being coal-fired base load generation. Many of them had constructed large base load units during the 1980s and, as a group, had surplus capacity that was disproportionately coal-fired base load capacity. Today, they have roughly 13,000 MW of installed or contractual capacity. None of them have added base load capacity since 1991; nor have they applied for general rate increases. Four have had rate decreases, and the other two utilities' rates have not changed. Overall, the total amount charged for electricity by the six utilities is less today than it was 10 years ago.

We reviewed the supply planning of each of the six major utilities. We conclude that Big Rivers, East Kentucky, LG&E and KU are responsibly addressing the long-term supply resource needs of their native load customers, either by adding new capacity or by arranging for long-term firm wholesale purchases at fixed prices. However, we have serious concerns about AEP-KY's plan to rely on market-priced wholesale power to meet a large portion of its system demand beyond the term of an existing firm purchase power contract that expires after 2004. We are also concerned that ULH&P has no announced plans for meeting its system demand when its full-requirements wholesale purchase power contract expires at the end of 2006.

We also reviewed the issues of appropriate reserve margins, reliance on purchased power and gas-fired peaking generation. We conclude that current reserve margins are appropriate, based on current conditions, but, given the pace of change within the industry, that the utilities should reassess their reserve margins in the near future. We also conclude that the utilities' current reliance on peaking generation and wholesale power purchases is appropriate, but that these issues should continue to be evaluated on an ongoing basis.

With rapid changes continuing to take place in the industry, we believe an annual review is needed to monitor our utilities' most recent assessments of their supply resources, future demand, reserve margins and need for new resources. Our Order requires the major jurisdictional utilities to file their first assessments by March 1, 2002.

Numerous issues were raised by participants in this proceeding such as creating a public power authority to develop coal-fired generation, the promotion of joint utility planning and ownership of generating capacity, and what role merchant power plants might have in meeting Kentucky's electric needs that are addressed herein. Other issues we address are the impact of demand-side management ("DSM"), the potential coordination of scheduled maintenance of generating units, and the siting of power plants and transmission facilities built by entities that we do not regulate.

We believe that policy issues regarding the creation of a public power authority lie within the realm of the Energy Board and suggest that it review this matter. We also believe that cost-effective DSM should be a part of all utility resource planning. We are requiring the six major utilities to conduct joint investigations of both shared ownership and coordinating maintenance schedules of base load generation. We believe there is need for a regulatory body in the state with jurisdiction over the siting of power plants and the siting of transmission facilities constructed by entities that do not fall under the our jurisdiction.

We conclude that merchant plant power may have a role in meeting the future energy needs of Kentucky and its citizens. Merchant plant power should be considered a resource option by our electric utilities, but purchases from merchant plants should be analyzed on the basis of cost and other factors, including the creditworthiness of the seller.

Transmission Issues

Transmission issues considered in this Order include: the adequacy of existing facilities; problem areas in the state's transmission grid; and whether the addition of new generation can be accommodated by the existing transmission system. These issues arise from changes brought about by FERC and electric restructuring in other states, changes that depend upon the existence of a functioning, competitive wholesale power market.

Possibly the most important issue for Kentucky is that transmission systems in the state were not designed to move large amounts of power through the state, and attempting to do so could threaten reliability of those transmission systems. Transmission Loading Relief ("TLR") procedures are in place to prevent overloads from occurring. However, these procedures can sometimes cause other problems on the transmission grid. FERC's answer to these problems is the development of Regional Transmission Organizations ("RTOs"), to which transmission owners will surrender operational control of their transmission systems. It is envisioned that RTOs will manage the systems in ways that will reduce existing problems and improve reliability through regional transmission planning. At present, it appears that two or possibly three RTOs will provide transmission service in Kentucky.

An engineering evaluation of the impact that proposed generating facilities would have on the transmission system in Kentucky, which was performed at the Commission's request, shows that the system is adequate to reliably serve native load as well as handle a significant portion of the proposed new generation. However, it also shows that the system was not designed to handle the type and volume of wholesale transactions contemplated by FERC and may need to be upgraded if it is to more fully support the future wholesale markets envisioned by FERC.

There are conflicting views on who should pay for upgrades or expansions necessary to accommodate the wholesale markets envisioned by FERC. Despite arguments to the contrary, there is no evidence of tangible economic benefits to Kentucky customers sufficient to justify their bearing the costs of such upgrades and expansions. Instead, it appears that economic benefits will most likely result for out-of-state customers that purchase power from these merchant plants. We conclude that the costs of upgrades and expansion required to accommodate new generation should continue to be borne by those who cause and who benefit from such upgrades.

We support federal and other states' efforts to promote the benefits of competitive wholesale markets; moreover, we are aware that transmission systems not designed to serve the uses being contemplated must be transformed to resemble an interstate highway system if federal and other states' goals are to be achieved.

Kentucky has achieved these same goals - low electric rates - under existing regulation, but we recognize that alternative approaches may work better elsewhere. We will do our best to cooperate with the federal government and other states to assist them in achieving their goals. Nevertheless, we cannot fulfill our duty to Kentucky customers by allowing them to help fund these efforts unless quantifiable benefits to those customers are clearly demonstrated.

Our transmission study indicates that roughly 6,000 to 7,800 MW of the more than 11,300 MW of generation proposed in Kentucky could be accommodated under peak conditions if constructed as proposed. Because of TLR and operating procedures, the proposed generation should not adversely affect the delivery of power to native load.

We conclude that our transmission system can reliably serve native load and a significant portion of the proposed merchant plants. However, it will not be able to handle the volume of transactions envisioned by FERC without future upgrades, the costs of which should be borne by those for whom the upgrades are required. We believe that new and emerging technologies should be considered as an alternative to installing additional transmission lines whenever new transmission capacity is needed.

We expect Kentucky to continue its existing regulation of utilities as a means of maintaining our low rates. For this reason, we do not envision Kentucky experiencing the sort of problems that have occurred elsewhere in the country that have had negative impacts on the electric utility industry. We conclude that future decisions on generation and transmission issues at both the regional and federal levels could have a profound effect on Kentucky. The Commission will continue to monitor all relevant issues and advocate Kentucky's interests at all opportunities.

DISCUSSION

Energy Policy Advisory Board

By Executive Order 2001-607, issued May 16, 2001, Governor Patton created the Energy Board to be responsible for planning and developing a coordinated statewide energy policy. Duties of the Energy Board, as established in that Order, include, among others: (1) making public policy recommendations to the Governor, General Assembly, and other federal, state, and local decision makers to promote affordable energy supplies, improve energy reliability, and enhance health, economic well-being, and environmental quality; (2) making recommendations on long-range energy supply and demand options with particular emphasis on energy resource development within the Commonwealth; and (3) assessing long-term demand for energy in the state and developing a plan for the adequacy of future electric generation and transmission.

The Chairman of the Commission was appointed as one of the 14 members of the Energy Board. For administrative purposes, the Energy Board has been attached to this Commission. The Energy Board has conducted four meetings at which representatives of Kentucky's regulated utilities, municipal utility systems, TVA, non-regulated merchant power plant developers, and various Kentucky government agencies presented testimony on issues related to generating capacity, adequacy of the state's transmission system, impacts of more stringent environmental regulations on the state's electric industry, and impacts of new merchant power plants being built or proposed in Kentucky.

Electric Industry Changes

Since 1990, when the most recent coal-fired base load generating unit was completed in Kentucky, several events have occurred that have profoundly changed the nature of the electric industry in the United States. First, Congress enacted the Energy Policy Act of 1992, which authorized utilities to create affiliates that can generate and sell power at wholesale and be exempt from all regulatory requirements of the Public Utility Holding Company Act of 1935. Second, in 1996 the FERC issued Order 888, which required utilities to open their transmission systems for use by wholesale customers on a nondiscriminatory basis ("open access transmission"), and authorized new wholesale power contracts to be at market-based, rather than cost-based, prices. It also issued Order 889, which required utilities to make public the terms and conditions of transmission service offerings at the same time such terms and conditions were made known to the utilities' electric generation and power trading business units. Third, many states with high electric rates have moved to restructure their retail electric markets by allowing the generation component of electric service to be sold at market prices. Fourth, in 1999 FERC issued Order 2000, which strongly encouraged utilities to turn over operational control of their transmission systems to RTOs, to facilitate the creation of robust competitive wholesale power markets.[3] Fifth, Congress has for a

[3] At least two RTOs, of which Kentucky's investor-owned electric utilities are members, the Midwest Independent System Operator ("Midwest ISO") and the Alliance

number of years debated and considered legislation to encourage, and possibly require, retail electric competition on a national basis.

These events initiated fundamental changes within the industry. Wholesale power markets have become much larger and more competitive, and generally prices are more volatile, especially during peak summer periods and, to a lesser extent, peak winter periods. Utilities have placed a greater emphasis on reducing costs and making organizational and structural changes necessary to become more competitive. This drive to reduce costs and be more competitive has led utilities to perceive a need to grow in size and achieve greater efficiencies through mergers and acquisitions. Each of the four major IOUs under this Commission's jurisdiction has been involved in one or more mergers or acquisitions in the past 10 years. A fifth major utility, Big Rivers, has also undergone a transformation by leasing its generating units to a non-regulated affiliate of LG&E, Western Kentucky Leasing Corp., and purchasing power from another non-regulated LG&E affiliate, LG&E Marketing, to meet most of its power requirements through 2022.

In addition, new environmental regulations have severely limited the amount of sulfur dioxide and nitrogen oxide that can be emitted by electric generating plants. This has required electric utilities to invest hundreds of millions of dollars in environmental systems and equipment to reduce emissions from coal-fired generating units. These investments have resulted in increases in the cost of generating power with existing

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RTO, will be in the Commonwealth. Possibly a third RTO, including TVA and other public power systems, will also be in Kentucky. More in-depth discussion of RTOs is coal-fired capacity in Kentucky and elsewhere.[4] These regulations have also resulted in a much greater reliance on natural gas as the fuel of choice for new generating facilities. This, in turn, has greatly increased the demand for natural gas and greatly increased the volatility of its market price.[5]

Many utilities that operate in jurisdictions that have endorsed retail competition, or are expected to do so, have been reluctant to make the significant capital investments necessary to construct new base load generation for fear that in a competitive environment some of their investment may be unrecoverable. This would create for those utilities what is commonly known in the industry as "stranded cost." Consequently, in the last decade, the trend among utilities nationally has been to invest in gas-fired, peaking capacity which has substantially lower capital costs compared to base load generation, and to rely more heavily on purchasing power from the wholesale market. Utilities have also reduced their capacity reserve margins, which represents the amount of generation available to a utility in excess of its peak load. Most utilities historically maintained a minimum planning reserve margin of 20 percent, but in recent years these planning reserve margins have declined with Kentucky's jurisdictional utilities planning margins ranging from 11 percent to 15 percent.

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included in the discussion of transmission issues that appears later in this Order.

[4] New nitrogen oxide limits go into effect in 2003. Most of the additional investments in related environmental systems have yet to be made and, therefore, have not yet been reflected in power costs.

[5] Electricity and natural gas have some of the most volatile prices among the commodities traded in the United States.

Electric Rates

Our July 2, 2001 Order noted that Kentucky has historically enjoyed some of the lowest electricity rates in the nation, along with high quality, reliable service. For our jurisdictional utilities, average retail rates for calendar year 2000 were as follows:[6]

	Residential	Commercial	Industrial	All Sectors
IOUs--Average Rates	5.2¢ / Kwh	4.9¢ / Kwh	4.0¢ / Kwh	4.9¢ / Kwh
Coops--Average Rates	6.1¢ / Kwh	5.9¢ / Kwh	3.3¢ / Kwh	5.6¢ / Kwh
Kentucky--Average Rates	5.5¢ / Kwh	5.2¢ / Kwh	3.9¢ / Kwh	5.1¢ / Kwh

A comparison with rates on a national and regional basis demonstrates the competitive advantage that Kentucky enjoys in terms of not only the price of electricity to consumers but also the economic development opportunities for attracting new industry and jobs to the Commonwealth. Following is a comparison of Kentucky's rates to the rates of states bordering it and to the nation as a whole:

[6] Average rates were calculated from information contained in the utilities' FERC Form 1 Annual Reports.

	Residential	Commercial	Industrial	All Sectors
Kentucky--Average Rates	5.5¢ / Kwh	5.2¢ / Kwh	3.9¢ / Kwh	5.1¢ / Kwh
Region--Average Rates[7]	7.3¢ / Kwh	6.3¢ / Kwh	4.2¢ / Kwh	5.8¢ / Kwh
Nation--Average Rates[8]	8.2¢ / Kwh	7.2¢ / Kwh	4.5¢ / Kwh	6.7¢ / Kwh

Kentucky's average rates for all sectors combined were 12 percent below the regional average and 23 percent below the national average in 2000. Following is a brief discussion of the process used to establish rates for a utility.

<u>Rate-Making</u>

Basically, rate-making involves an analysis to determine a utility's reasonable level of operating expenses plus a reasonable return or profit on the utility's investment in equipment and facilities. The sum of a utility's reasonable expenses plus a return equals its revenue requirement, which is the amount of revenue that needs to be produced by the utility's rates. Once the revenue requirement is determined, the rates necessary to generate that revenue level can be calculated based on normal sales volumes. Because of diverse usage levels and usage patterns by a utility's different customer classes, the actual rates for each class of customers will vary for the utility. Similarly, rates will vary from utility to utility due to the unique operating characteristics of each utility. For electric utilities, there are three general factors that typically account

[7] The region includes the following states: Illinois, Indiana, Missouri, Ohio, Tennessee, Virginia and West Virginia. Average rates were calculated from data contained in Tables A21 through A24 published by the U.S. Department of Energy's Energy Information Administration.

for the lion's share of these variations in operating characteristics and, hence, rates. First is the age of the utility's generating units, since older units generally have lower costs per KW of capacity than newer units. Second is the extent to which the generating units were required to be equipped with various environmental systems for the purpose of reducing emissions levels, since additional environmental equipment results in higher installed costs per KW of capacity. Third is the manner in which the financing costs are accounted for during the multi-year period necessary to construct major generating units. Capitalizing the financing costs increases the installed cost per KW of capacity compared to expensing the financing costs during construction.

Electric Restructuring

Our July 2, 2001 Order also noted that Kentucky's low electric rates were substantially due to its historic reliance on coal-fired base load generation sold at cost-based rates.[9] That Order further stated that electric restructuring, the process by which retail customers are granted the right to choose their supplier of electric generation, does not appear to be imminent in Kentucky. However, recent events in California and other western states have shown that adverse impacts of electric restructuring are not limited by artificial boundaries such as state borders. Consequently, California's flawed restructuring plan resulted in electric shortages and price spikes throughout the Western United States.

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[8] National average rates shown in EIA Tables A21 through A24 published by the U.S. Department of Energy's Energy Information Administration.

[9] Sound utility management, excellent public policy adopted by the General Assembly, and reasonable regulatory oversight have also contributed to the low rates.

Many states that border Kentucky have either adopted, or are considering adopting, electric restructuring. These restructuring efforts have already impacted wholesale electric markets, which are regional in scope, and Kentucky's regulated utilities, who buy and sell power at wholesale on a regular basis. The impacts of restructuring, along with potential impacts of utilities' increased reliance on peaking generation fueled by natural gas, with its recent price volatility, were areas the July 2, 2001 Order indicated would be explored in the course of this proceeding.

As a result of electric restructuring enacted in Ohio in 1999, Ohio affiliates of AEP/KY and ULH&P are not willing to sell power to their Kentucky affiliates at cost-based rates beyond the expiration of their current sales agreements. Electric utilities in Ohio are transferring their generating assets to non-regulated affiliates in order to sell power at market-based rates. This has the potential to reduce the capacity available for Kentucky and increase retail prices for electricity supplied by Ohio utilities at rates that will be market-based, rather than cost-based.

Kentucky's Electric Utilities

Kentucky's six major jurisdictional utilities reflect different types of electric systems. Two of the utilities, East Kentucky and Big Rivers, are not-for-profit generation and transmission cooperatives operating entirely within Kentucky, although Big Rivers no longer operates its generating units. Two utilities, AEP-KY and ULH&P, are IOUs that are part of multi-state holding companies, which rely on their affiliates, either in whole or in part, to meet their full power requirements. The other two utilities, LG&E

and KU, are in-state IOUs that are subsidiaries of the same holding company, own and operate their own generating capacity, and are jointly planned and dispatched.

In addition to these six Commission-regulated electric utilities, there are 55 other electric utility systems operating in Kentucky. Those include 20 distribution cooperatives and one private distribution system, which are subject to the Commission's jurisdiction, plus 29 municipal systems, TVA and 5 TVA-supplied cooperatives that are not regulated by the Commission. To provide some perspective on the adequacy of the current level of generating capacity in Kentucky, it is necessary to briefly review demand forecasting and supply planning, generally, and over the past decade, on a utility-specific basis.

DEMAND FORECASTING/SUPPLY PLANNING

Overview

The starting point for utility planning is the development of a demand, or load, forecast. A load forecast serves to guide the utility in many decisions, such as: (1) whether to construct generation or purchase capacity from other sources; (2) the timing of capacity additions; (3) the type of capacity to be added; (4) the required size of capacity additions; and (5) likely sites for constructing new generating units. Utilities rely on historical data, including growth in the number of customers and sales volumes for their own systems. In addition, utilities evaluate the relationships between that data and economic conditions, population trends, and prices of various fuels and competing energy sources over the historical period.

Utilities' load forecasts also entail analysis of current data and forecast data, including, among other things, long-term economic forecasts, population projections, improved appliance efficiencies, and potential changes, either domestic or foreign, that may impact energy prices and energy-intensive industries. For much of the forecast data, the utilities rely on various government or industry service providers involved in reporting such data, as well as information provided directly by their large customers. For population data, four of the six major jurisdictional electric utilities use the State Data Center as a data source.

Today, the major electric utilities own and operate nearly 10,000 MW of generation and have contractual entitlements to roughly 3,000 MW of generation, for a total of 13,000 MW.[10] This reflects capacity owned by, or available under contracts to, Big Rivers, East Kentucky, AEP-KY, KU, LG&E, and ULH&P. The long-term capacity available under contracts is supplied by the Southeast Power Administration ("SEPA"), AEP Electric Generating Co., The Cincinnati Gas and Electric Company ("CG&E"), Owensboro Municipal, Electric Energy Inc. ("EEI"), LG&E Energy Marketing ("LG&E Marketing"), and Ohio Valley Electric Corporation ("OVEC").[11] The two largest buyers of contract power are ULH&P, whose current capacity requirement of approximately 850 MW is supplied under a full-requirements wholesale power contract with its parent,

[10] Appendix B identifies the generation owned by each utility.

[11] East Kentucky has entered into a number of short-term capacity arrangements in addition to its long-term arrangement with SEPA.

CG&E, and Big Rivers, which has 775 MW of capacity available to it under contracts with LG&E Marketing and SEPA. Of the 29 municipal systems, two, Henderson Municipal Power & Light and Owensboro Municipal, have their own generation. TVA, which supplies parts of Kentucky and six other states, has 4,500 MW of generation in Kentucky, and a total of 30,000 MW of generation throughout its system.

In 1991, the six major jurisdictional utilities filed their initial Integrated Resource Plans ("IRPs") with the Commission, pursuant to 807 KAR 5:058. An IRP is a report that details a utility's current load forecast of its future demand and its plans for meeting that future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers, while complying with all relevant state and federal laws and regulations. In those IRPs, the utilities provided information regarding, among other things, load forecasts, existing generation, planned capacity additions, and reliance on purchased power. The information, shown in Appendix C, indicated the utilities' combined forecasted coincident native load peak demand in the summer of 1992 would be 9,256 MW, with an overall summer reserve margin of 26.3 percent. The information also indicated that the combined coincident native load peak demand in the winter of 1992 would be 8,568 MW, with an overall winter reserve margin of 35.2 percent. Of roughly 11,000 MW of installed or contractual capacity available to the six jurisdictional utilities at that time, over 95 percent was coal-fired base load generation. Four of those utilities, Big Rivers, East Kentucky, KU, and LG&E, had constructed large base load generating units during the 1980s. In aggregate, the generating utilities had surplus generating capacity that was disproportionately coal-fired base load capacity.

Since the filing of those IRPs, none of the six major electric utilities has applied for a general rate increase. Big Rivers, East Kentucky, LG&E and KU have had general rate decreases since that time, while AEP-KY's and ULH&P's rates have not changed. While increases in fuel costs, environmental costs, and DSM costs have been reflected in their utilities' automatic adjustment clauses and surcharges, the total amount charged for electricity by the six major utilities is lower today than it was 10 years ago.

The following parts of this section discuss the demand forecasts and resource supply plans of each jurisdictional utility.

Big Rivers

Big Rivers, which provides power at wholesale to three distribution cooperatives in western Kentucky, has gone through significant changes over the past several years. Historically, its load was dominated by two very large aluminum smelting customers and 15 to 20 other large industrial customers that, collectively, accounted for approximately three-fourths of its electricity sales. It encountered financial problems beginning in the 1980s due to the debt incurred to construct its newest generating plant, Wilson, and its inability to successfully market what was then relatively high cost capacity from that plant. Big Rivers ultimately filed for bankruptcy in 1996 and reorganized its operations by leasing all of its generating capacity to Western Kentucky Leasing Corp., an unregulated affiliate of LG&E. In a companion transaction, Big Rivers began purchasing power from LG&E Marketing, another unregulated affiliate of LG&E, at fixed prices up to a specified amount of capacity to serve its native load. The two aluminum smelters are no longer included in Big Rivers' load; they are served through a distribution cooperative member of Big Rivers' system, Kenergy, under separate power contracts between Kenergy and LG&E Marketing.

Through the 2010 forecast period, Big Rivers has 597 MW available from LG&E Marketing plus 178 MW available from SEPA through the U.S. Army Corps of Engineers, for a total of 775 MW. Through 2010, Big Rivers' native load firm peak demand is projected to range from a low of 632 MW in 2002 to a high of 725 MW in 2010.[12]

Big Rivers is able to market power that is in excess of its system's needs in the open market, plus it can purchase power from the market if market prices fall below the price it is charged by LG&E Marketing. Big Rivers does not have a specific reserve margin requirement in large part because its power purchase from LG&E Marketing is firm, rather than being contingent on the availability of specific generating units. This is reasonable as long as the 775 MW that it purchases is significantly greater than its forecast peak demand. Although it has no reserve margin requirement *per se*, with the demand levels it currently projects, Big Rivers expects its reserve margins during the forecast period to range from 22.5 percent in 2002 to 6.9 percent in 2010.

Big Rivers' plans for meeting its demand requirements entirely through purchased power arrangements have previously been approved by the Commission. Through 2010, it appears there will be no need for it to either purchase power from

[12] Forecasted demand, capacity, and reserve margins for the six major jurisdictional utilities are shown in Appendix D to this Order.

sources other than LG&E Marketing and SEPA or construct new capacity in order to meet its native load demand. While it forecasts no need for new capacity over the 2002-2010 planning period, Big Rivers indicates that if such a need arises, it will evaluate all available supply resource options just as it would if it were presently operating its own generating capacity.

Under the terms of its long-term purchase power arrangements with LG&E Marketing and SEPA, Big Rivers has its supply resource needs addressed for the foreseeable future. We continue to be encouraged by the results of this arrangement, particularly by the fact that Big Rivers' power purchases are at fixed prices that are not subject to market price risk and fuel price fluctuations.

East Kentucky

East Kentucky has historically depended primarily on its own installed generating capacity to meet its native load requirements with some reliance on purchased power to meet its peak demand and its reserve margin requirements. East Kentucky serves a largely rural, largely residential customer base in central and eastern Kentucky through 17 distribution cooperatives.[13] It is a winter peaking system and is heavily inter-connected with KU due to the contiguous nature of their respective service territories and joint use of transmission facilities. East Kentucky owns and operates nearly 1,500

[13] Two cooperatives, Blue Grass Energy and Harrison Electric, have approved a consolidation that will become effective January 1, 2002, resulting in a total of 16 cooperatives served by East Kentucky.

MW of coal-fired base load generating capacity, all of which was installed prior to 1981. It also owns and operates five CTs, installed since 1995, which provide peaking capacity ranging from roughly 550 MW in the summer to 650 MW in the winter. In addition to its own generation, East Kentucky has 170 MW of capacity available under a long-term arrangement with SEPA.

Historically, East Kentucky used 20 percent for its planning reserve margin. However, in recent years, consistent with industry trends, it has reduced its planning reserve margin, and currently uses a reserve margin of 15 percent for planning purposes. In both 1999 and 2000, its native load sales were slightly greater than its generation levels.[14] Also, due to forced outages, higher than normal demand, and regional transmission constraints, it experienced negative reserve margins on a limited number of occasions during those years.

East Kentucky's forecast native load firm peak demand through 2010 ranges from 2,323 MW in 2002 to 2,973 MW in 2010. In addition to its existing capacity, it expects to add 270 MW of new base load generating capacity during the forecast period. It also has a long-term contract to purchase 540 MW of capacity from Kentucky Pioneer Energy ("KPE") from a gasification combined cycle plant to be constructed at East Kentucky's J.K. Smith generating site in Clark County, Kentucky. The plant will burn a combination of solid municipal waste and coal, but the developers have been

[14] A summary of each utility's calendar year 2000 peak demand, generation, purchases, and sales is shown in Appendix E.

unable to obtain financing and the project's fate is uncertain. In addition, East Kentucky expects to increase its peaking capacity by approximately 200 MW over the forecast period. Due to the expected timing of its capacity additions, in some years over the forecast period ended 2010 East Kentucky expects to rely on firm capacity purchases in varying amounts up to a maximum of 450 MW in 2004.

East Kentucky projects relying on purchased power, to a fairly significant extent, to meet its winter reserve margin requirements. Although it has added peaking capacity in the form of CTs in recent years, East Kentucky has opted to balance its supply portfolio to a certain extent by purchasing peaking power for the winter season rather than build additional peaking capacity for which it would incur fixed costs on a year-round basis. Because its system peak occurs during the winter, which is the off-peak period for most utilities in the Midwest / East Central Area Reliability ("ECAR") region, East Kentucky is able to rely on firm capacity purchases to cover its reserve margins during its peak season at fairly reasonable winter market prices.[15] Based on its planned capacity additions and power purchases, East Kentucky projects it will have winter reserve margins over the forecast period ranging from 14.8 percent to 16.1 percent.

We note that East Kentucky has, at times in the past, engaged in diversity power exchanges, where one utility with a summer peak and another utility with a winter peak exchange power such that in one utility's off-peak season it is supplying power to the

[15] While there are certain risks associated with this strategy, it is less expensive than constructing new capacity and paying for it on a year-round basis to meet a demand that exists for only a few hours of the year.

second utility during the second utility's peak season.[16] Although they still provide obvious benefits to the utilities involved, for various reasons such diversity exchanges have become less attractive to utilities in recent years. We strongly encourage all of our regulated utilities to explore the potential for such exchanges in the future as a means of continuing to provide safe, reliable electric service in a cost-effective manner to Kentucky ratepayers.

East Kentucky plans to add both base load capacity and peaking capacity during the 2002 - 2010 planning horizon. Its resource plans are based on its 2000 IRP analysis, which reflects the unique characteristics of its existing resource mix, existing system load, and forecast demand growth. Based on its most recent IRP and the information provided in this proceeding, East Kentucky is responsibly planning to meet its obligation to serve native load customers in a reliable manner at reasonable costs.

LG&E/KU

LG&E is a combination gas and electric utility serving a predominately urban customer base in the greater Louisville - Jefferson County area. KU is an electric only utility serving a rather diverse customer base throughout the central, southeastern, and western portions of Kentucky. Traditionally, each utility depended primarily on its own generation, with some degree of reliance on purchased power, to meet its native load demand. Although these two utilities have undergone a number of changes in recent

[16] East Kentucky made such exchanges with LG&E and CG&E for a number of years.

years beginning with the merger of their respective holding companies in 1998, followed by the acquisition of their parent company, LG&E Energy, by other utilities over the past 2 years,[17] the manner in which they plan on addressing their capacity requirements has not changed significantly since the early 1990s.

LG&E/KU owned and operated approximately 5,400 MW of base load capacity in 1991, and that amount remains unchanged today. They owned and operated roughly 200 MW of peaking capacity at that time and since 1994 have installed roughly 1,250 MW of additional peaking capacity in the form of CTs. In addition, LG&E/KU have access to nearly 600 MW of capacity through long-term contracts with EEI, Owensboro Municipal, and OVEC. The combination of owned and contractual capacity results in total supply-side resources of nearly 7,500 MW at present, with plans to install an additional 300 MW of peaking capacity in 2002.

LG&E/KU forecast their firm native load peak demand over the forecast period to range from 6,705 MW in 2002 up to 7,883 MW in 2010. Over that period, they project adding approximately 1,400 MW of new peaking capacity and achieving roughly 150 MW of demand reductions through new DSM programs initiated in 2001.[18] This will result in total available resources of approximately 9,000 MW in 2010, assuming no deratings or reductions to their existing capacity resources.

[17] LG&E Energy was acquired by PowerGen plc in 2001. Its acquisition by E.ON is expected to be completed in early 2002.

[18] LG&E/KU's projected increases in supply resources are consistent with their 1999 Joint IRP and their individual IRPs filed prior to their merger.

In the early 1990s, both LG&E and KU used 20 percent reserve margins for planning purposes. Immediately prior to their 1998 merger, LG&E used a 16 percent planning reserve margin while KU used 17.6 percent. After the merger, they reduced their combined planning reserve margin to 14 percent. Based on the reserve margin analysis included in their 1999 Joint IRP, LG&E/KU adopted a base case planning reserve margin of 12 percent based on an optimal reserve margin range of 11 to 14 percent. With their planned capacity additions and DSM programs, they project a reserve margin within or above that range throughout the forecast period.

LG&E/KU have for several years utilized a fairly traditional planning strategy of evaluating the options of purchasing power versus building new generating capacity. They did so separately prior to their merger and have done so on a joint basis since 1998. In the past 10 years they have relied on firm power purchases to meet reserve requirements during periods when new capacity was being constructed.

Owensboro Municipal and MEPAK express concern that LG&E/KU have reduced their planning reserve margins in recent years and suggest that the Commission require all generating utilities to adopt a minimum planning reserve margin of 15 percent.[19] It is correct that all of Kentucky's jurisdictional utilities have reduced their reserve margins in recent years. Such reductions are consistent with changes in the electric industry, particularly the advent of open access transmission, increased wholesale competition

[19] The information provided in this proceeding indicates LG&E/KU were the only jurisdictional generating utilities that did not experience negative reserve margins at some point over the 1999 – 2000 period and that their native load exceeded their installed base load capacity in only 5 months during that 24-month period.

and retail restructuring in several states across the country. In spite of their criticisms of the reductions in reserve margins by Kentucky's utilities, no intervenor offered any evidence to contradict the results of the reserve margin studies the major generating utilities have provided in past IRP filings.[20] The reserve margin study included in the LG&E/KU 1999 Joint IRP appears to be reasonable based on market conditions and other factors utilized at that time. However, we expect LG&E/KU and the other generating utilities to thoroughly analyze the issue of an appropriate planning reserve margin as part of their next scheduled IRP filings in 2002-2003.

Owensboro Municipal, MEPAK and Gallatin Steel took issue generally with the utilities' degree of reliance on gas-fired peaking generation and purchased power.[21] While we appreciate their interest and participation in this proceeding, we must point out that Owensboro Municipal and a number of other MEPAK members are wholesale customers served by KU, and that such service is subject to the exclusive jurisdiction of FERC, not this Commission. Likewise, Gallatin Steel's service from LG&E is provided through a wholesale power agreement that is not subject to this Commission's jurisdiction. Having made this point, we note that all applications for approval to

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[20] The information supplied by TVA shows that its planning reserve margin is 13 percent through 2010 and declines to 12 percent for the period 2011 through 2020.

[21] While they raised many issues in a rather generic manner, the primary interests of Owensboro Municipal, MEPAK, and Gallatin Steel are the wholesale power arrangements under which they are served by either KU or LG&E.

construct gas-fired peaking capacity, including LG&E/KU's applications, have been thoroughly evaluated by this Commission. We have been satisfied in those proceedings that the proposed construction was appropriate to meet the utilities' load requirements as opposed to constructing base load capacity. Likewise, through various formal and informal proceedings, we review the utilities' purchased power arrangements and, given the changes within the industry, we have concluded that such arrangements are a reasonable means for meeting their power supply requirements.

LG&E/KU have added capacity in recent years and have plans to add additional capacity over the 2002 - 2010 planning horizon. The additions planned at present are all CT peaking capacity. This is consistent with the analysis contained in LG&E/KU's 1999 Joint IRP. However, we note that LG&E/KU report that forward wholesale market prices for the Midwest are increasing during non-peak periods, and that such increases are an indication that the region is, at times, short of base load capacity and that there may be a need for more base load capacity in the region. LG&E/KU indicate this is one of the issues being reviewed in the development of their 2002 IRP.[22]

LG&E/KU evaluate their supply resource requirements on an ongoing basis to determine if a purchased power option might be more economic in the long term or, on a short-term basis, might economically defer the need to invest in new generation. Largely due to their system peaks occurring in the summer, when market prices tend to

[22] Transcript of Evidence, September 19, 2001, at 222-223.

be their highest, LG&E/KU's plans include adding new generation without relying on purchased power except for their existing arrangements with EEI, Owensboro Municipal, and OVEC. Their current resource plans reflect the results of their 1999 Joint IRP, as well as their recently approved DSM programs and other updated information. Based on a review of these resource plans, LG&E/KU are responsibly planning to meet their obligation to serve their customers in a reasonable, cost-effective manner.

AEP-KY

AEP-KY is a subsidiary of American Electric Power Company, Inc. ("AEP"), a multi-state holding company that provides electric service in 11 states in the midwestern and south-central United States. Five AEP subsidiaries, including AEP-KY, are members of a power pool known as AEP-East. AEP-KY serves portions of eastern Kentucky and its generating capacity consists of the two Big Sandy units ("Big Sandy") located in Louisa, Kentucky. These are coal-fired base load units with a combined output of 1,060 MW. In addition, AEP-KY purchases 390 MW of capacity from the Rockport Station ("Rockport"), which is owned by an affiliate in southern Indiana, under the terms of a unit power agreement that runs through 2004. This results in total available capacity of 1,450 MW for AEP-KY. Also, as a member of AEP-East, AEP-KY is able to call on other pool members to supplement its power resources as the need arises. In the early 1990s, AEP-East used an 18 percent reserve margin for planning purposes. However, for the past several years, it has used 12 percent. Because

AEP-East is centrally dispatched and operated, individual pool members are not required to develop company-specific planning reserve margins.

For the forecast period, AEP-KY projects native load peak demands increasing from 1,538 MW in 2002 to 1,752 MW in 2010. Peak demand will exceed the capacity available from Big Sandy and Rockport by as much as 150 MW in 2004 and, after the Rockport agreement terminates, peak demand will exceed the Big Sandy capacity by nearly 700 MW in 2010. AEP-KY plans to rely on wholesale power purchases, either from AEP affiliates or non-affiliated energy providers, to cover the capacity shortfall it projects during the latter years of the forecast period.

Only recently has AEP-KY's peak demand exceeded its available capacity of 1,450 MW. However, with projected demand growth and the expiration of the Rockport agreement, it will need to purchase roughly 600 to 700 MW to meet its peak demand beginning in 2005. Based on the significant quantity of new generation being proposed in the Midwest over the next several years, AEP-KY maintains that if even a fraction of that generation is built, there should be sufficient capacity in the region to meet its needs without constructing generation itself.[23]

Historically, AEP-East has maintained a relative balance between members such as AEP-KY that have winter-peaking loads and other members that have summer-peaking loads. Because of this balance and the relatively few hours that AEP-KY's

[23] We note that, at least in this case, no other regulated Kentucky utility expressed this same point of view.

demand has exceeded its available capacity, AEP-KY has been a large volume net seller to AEP-East. The revenues from these power pool sales have worked to the advantage of AEP-KY and its ratepayers.

Recently, in conjunction with electric restructuring involving subsidiaries that operate in Ohio and Texas, AEP has proposed a corporate restructuring. That proposal, now pending at FERC, would reduce AEP-East from five to three members by eliminating the Ohio members and transferring their generation to an unregulated affiliate.

With AEP-East consisting of five members with over 22,000 MW of capacity subject to cost-based regulation, the fact that AEP-KY did not incorporate a company-specific reserve margin in its resource planning was of little consequence. However, with AEP-East poised to lose two members and a substantial part of its generation, AEP-KY's decision to rely on the wholesale market to meet the requirements of its customers above the output of its Big Sandy station is a concern to the Commission.

Clearly, the proposal to reduce AEP-East to three members has the potential to significantly impact the operating flexibility and reliability that historically has been available to AEP-KY as a member of that pool. Reliance on purchased power in and of itself is not the issue so much as the degree to which purchased power is relied upon, the type of purchased power and the price, terms, and conditions under which that power will be purchased. The Commission believes that reliance on power purchases that reflect market price volatility is not in the best interests of Kentucky consumers. AEP-KY must plan to meet its load by securing sufficient capacity that is not subject to market price volatility. Only by doing so will AEP-KY be able to maintain reasonable electric rates while mitigating to the extent possible market price and fuel price fluctuations. The Commission has intervened at the FERC in AEP's pending restructuring case. We have asserted that the Rockport unit power purchases should be extended beyond their 2004 expiration and negotiations on that issue are ongoing. We look forward to continuing to address this matter in the future in a constructive manner that will result in a positive outcome for AEP-KY and its customers.

ULH&P

ULH&P, a combination gas and electric utility with its service territory in northern Kentucky, is a wholly owned subsidiary of CG&E, on whom it has historically relied to supply 100 percent of its power requirements through a FERC-approved wholesale power contract. CG&E, which merged with Public Service Indiana ("PSI") in 1995 to form Cinergy Corp., utilizes a central dispatch to serve ULH&P, which owns no generation. Under its purchase power arrangement with CG&E, ULH&P has not had to develop a planning reserve margin of its own, although CG&E has used a 17 percent reserve margin for planning purposes.

ULH&P forecasts its native load peak demand to range from 842 MW in 2002 to 970 MW in 2010 with its demand being met via its wholesale power contract through 2006. However, that contract expires at the end of 2006 and ULH&P has announced no specific plans for addressing its supply-side requirements thereafter. CG&E, which is subject to deregulation in Ohio, is undergoing a corporate separation that will result in its generation being transferred to a non-regulated affiliate that will sell power at market-based, rather than cost-based prices. ULH&P has agreed to file a stand-alone IRP by June 30, 2004, so the Commission may initiate a formal investigation to address ULH&P's post-contract supply requirements. It has also agreed to cooperate in good faith should the Commission initiate such a review prior to that date.

The Commission has previously approved ULH&P's plan to meet its demand requirements through 2006 by purchasing 100 percent of its wholesale power under a fixed price contract with CG&E. As noted above, ULH&P has no announced plans to meet its load after 2006. Since CG&E's generation is being deregulated and will be sold at market-based prices, ULH&P will soon need to address the issue of meeting its post-2006 power requirements in the most reasonable, least costly manner. While it has committed to filing a stand-alone IRP in 2004, the Commission anticipates initiating a review of ULH&P's long-term power supply requirements at some earlier date.

SUPPLY RESOURCE ISSUES

A number of supply resource issues brought out in this proceeding are more appropriately discussed on a general, statewide basis rather than a utility-specific basis. Such issues include reliance on gas-fired generation, public power-joint ownership, DSM, and the impact of merchant power plants. Those issues are discussed in the following portions of this Order.[24]

[24] Discussion of the issues of adequate reserve margins and reliance on purchased power were included in the LG&E/KU section.

Gas-Fired Generation and Natural Gas Prices

The utilities were questioned about the impact of natural gas price volatility on their planning and their anticipated reliance on gas-fired CTs in the future. Generally, they indicated that the fuel price sensitivity analyses conducted as part of their IRP processes address these issues. The results of such analyses indicate that, over the long term, gas-fired peaking capacity is still an appropriate form of generation to include in their supply-side resource portfolios.

Gallatin Steel, questioning the utilities' reliance on purchased power and gas-fired peaking generation and, citing the fact that base load capacity has not been built in Kentucky since 1990, recommends adding coal-fired base load capacity to mitigate the impact of natural gas price volatility on retail electric rates. We note that prior to the natural gas price spikes of late 2000 and early 2001, which were outside the control of the electric utilities, we had received no complaints concerning the state's mix of generating capacity. Likewise, no objections have been filed in previous Commission proceedings involving the construction of gas-fired peaking capacity by our jurisdictional utilities. We note that as an industrial customer with a large interruptible load, Gallatin Steel's rate recovers a lower portion of the capital costs associated with the investment in base load generating capacity than do the rates of customers with entirely firm loads. Obviously, the construction and operation of base load capacity, with relatively low fuel costs, to the exclusion of higher-fuel cost peaking capacity, would be economically beneficial to an interruptible customer such as Gallatin Steel, even though it might be economically detrimental to virtually all other customers.

As noted previously, the jurisdictional utilities collectively had excess base load capacity in 1991. Beginning with the 1991 IRP filings, the resource plans of the six major jurisdictional utilities have been reviewed and reported on by Commission Staff. In the past 10 years, the Commission has formally reviewed, prior to approving, construction of 13 gas-fired peaking units. Nothing presented in this proceeding persuades the Commission that the current degree of reliance on gas-fired peaking generation by the jurisdictional utilities is inappropriate or unwarranted.

Public Power-Joint Ownership

Gallatin Steel recommends creating a public power authority to develop the state's coal-fired generating resources and market the output at cost-based rates to Kentucky's retail distribution utilities. It states that the primary objective would be to maximize benefits from increased use of Kentucky coal, adjusted to reflect external costs associated with increased coal use.[25] Gallatin Steel indicates the Commission should encourage joint utility planning and ownership, while the Energy Board should consider establishing a public power authority.[26]

LG&E/KU argue that utilities are uniquely qualified and best suited to determine the resource needs and acquisition plans that are most appropriate to meet their customers' requirements. They cite the Commission's IRP process to support their

[25] Gallatin Steel brief at 11.

[26] Id. at 13.

position.[27] Intervenor Madison opposes establishing a public power authority on the grounds it would create additional bureaucracy. However, he appears to agree that it may be an appropriate issue to be addressed by the Energy Board.[28] Intervenor Madison agrees that the Commission should explore joint building of coal-fired power plants instead of gas-fired peaking units.[29]

The Governor directed the Commission to give consideration to means by which the utilization of Kentucky coal can be preserved and enhanced. The establishment of a public power authority to develop and market coal-fired generation appears to be one such means. However, determining the feasibility of establishing a public power authority will require an analysis of complex issues far beyond the scope of the Commission's jurisdiction. Recognizing that the Energy Board has been empowered with a broad directive to develop a strategic energy plan for the Commonwealth, the Commission believes it would be appropriate for the Energy Board to give this issue further consideration.

East Kentucky is in the process of adding base load capacity. With off-peak power prices increasing, it appears possible that additional base load generation may be added to Kentucky's capacity mix in the future. Although the Commission recognizes that the utilities may have different or conflicting corporate directives, we believe it is essential to the interests of the ratepayers and the economic development of Kentucky

[27] LG&E/KU brief at 13.

[28] Madison brief at 12.

that our utilities formally consider joint ownership opportunities that could benefit all parties.[30]

The Commission recognizes that the capital investment in base load generation is extremely significant and the historic practice of a utility building a large coal-fired base load unit knowing that its load would grow into that capacity in just a few years has long since passed. However, we also recognize that economies of scale can still be achieved by adding generation in large increments and that the addition of coal-fired base load generation, when warranted, is beneficial to the economic well-being of Kentucky's coal industry and the Commonwealth as a whole. For these reasons, we will require our jurisdictional electric utilities to conduct a joint investigation of the feasibility of shared ownership of future base load generation to meet changes and growth in Kentucky's electric demand. A joint report summarizing this investigation and the conclusions reached should be filed no later than July 1, 2002.

<u>Demand-Side Management</u>

All the major jurisdictional utilities have evaluated DSM in past IRPs and have included DSM in their resource plans. The Division of Energy states that new and enhanced DSM programs, in combination with planned capacity additions, could help relieve the shortfall between electric demand and supply. While the Division of Energy

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[29] Id. at 11.

[30] Joint ownership may be especially appropriate for utilities with peak demands occurring in different seasons.

notes that our jurisdictional utilities are beginning to implement DSM programs on a noticeable scale, it asserts that many DSM programs that help customers improve their energy efficiency that are technically feasible and cost-effective have not been implemented. The Division of Energy suggests that comprehensive review of the adequacy of Kentucky's generation should note the potential for DSM programs to reduce the overall need for new generation.[31]

The Division of Energy also cites the benefits of integrated resource planning on a localized level and suggests that its advantages also support cogeneration and other forms of distributed generation.[32] The Division of Energy states that net metering could make small-scale distributed generation projects economically feasible and notes that, in light of the events of September 11, 2001, greater installation of distributed generation and construction of more energy-efficient buildings would help utilities be less vulnerable to catastrophic failure.[33]

LG&E/KU filed information updating their plans for addressing capacity requirements through 2010. Through 2005, LG&E/KU intend to implement DSM programs that will contribute over 150 MW of capacity toward meeting those needs. LG&E/KU refer to their DSM proceedings before the Commission as support for the

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[31] Young testimony at 4-6.

[32] Id. at 9.

[33] Id. at 12.

reasonableness of their consideration of DSM programs.[34] As to the Division of Energy's comments on net metering, the Commission notes that LG&E and KU have recently filed net metering tariffs. These tariffs are currently being reviewed by the Commission.

ULH&P indicates that it is considering also filing a net metering tariff stating that such a tariff will allow customers with photo-voltaic generation to make use of that generation while having its power as a backup. ULH&P also notes that such a tariff will support environmentally friendly generation sources.[35]

The Commission believes that DSM is a critical part of any evaluation of resources needs. DSM will continue to be reviewed as part of the utilities' IRPs and in formal Commission DSM proceedings. Kentucky's jurisdictional utilities will be expected to continually evaluate DSM programs and implement those that are cost effective. The Commission looks forward to working with the Division of Energy and the utilities on DSM in the future.

Impacts of Merchant Power Plants on Resource Planning[36]

Thoroughbred Generating was the only merchant power plant developer to testify in this proceeding. However, in presentations to the Energy Board, merchant plant owners described such plants as important economic resources. They strongly encouraged the Energy Board, jurisdictional utilities, and others to consider purchasing

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[34] Response to Question 6, Order dated July 2, 2001.

[35] ULH&P brief at 15.

from merchant plants when reviewing the need for additional power resources to serve Kentucky's native load customers.

Thoroughbred Generating, a subsidiary of Peabody Energy, a major coal producer, proposes to build a 1,500 MW mine mouth clean-coal generating plant in Muhlenberg County, Kentucky.[37] According to Thoroughbred Generating, developing low cost coal-fired generation is good for Kentucky because it will create jobs, produce low cost energy that will keep and attract new industry, and reduce Kentucky's dependence on external energy resources.[38] Thoroughbred Generating states that the best way to ensure expansion of the Kentucky coal market and to retain related jobs and economic benefits is to build mine mouth coal-fired generation in the state.[39] While Thoroughbred Generating's testimony specifically advocates the value of mine mouth plants, the stated importance of the impact of merchant plants on Kentucky is consistent with the position taken by other merchant plant developers and the merchant plant industry association concerning merchant plants generally.

The merchant plant industry association, known as the Electric Power Supply Association ("EPSA"), made a presentation to the Energy Board on September 25, 2001. According to EPSA, owners of merchant plants look for long-term buyers for their power or sell it on the open market. Most merchant plants employ a combination of

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[36] A list of proposed generation plants is attached at Appendix F to this Order.
[37] Williams testimony at 1.

[38] Id. at 2.

[39] Id. at 3.

these strategies where they guarantee a base load of power and by doing so help large suppliers ensure a reliable flow of electricity to their customers. Other merchant plants operate as part of regional power pools while some are peaking plants that come online only when power needs are greatest.[40] EPSA explained that as new and cleaner merchant plants come online, older and less efficient power plants can be retired or can be converted to peaking units.[41]

EPSA states that merchant plants respond to the market; to lessen risk, however, many plants seek to enter into long-term contracts to sell all or part of their output. The length of such contracts is often tied to the length of time needed to retire the debt incurred to construct the plant. The siting of merchant plants within the state and in areas where the need is greatest will decrease the burden on transmission grids and lessen the need for additional transmission construction and maintenance, according to EPSA. Building merchant plants can also reduce dependence on out-of-state energy supplies, which, EPSA asserts, help energy markets stabilize and ease price pressures.[42]

According to EPSA, even states that currently have sufficient power supplies and reserve margins can find those reserve margins shrinking quickly if construction of new power plants does not keep up with demand.[43] EPSA contends that even if Kentucky

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[40] Energy Board Transcript, September 25, 2001, at 6.

[41] Id. at 8.

[42] Id. at 9.

[43] Id. at 14.

does not yet need additional power, competitive power suppliers now building here will be selling power elsewhere, enabling them to pay off their plant investment and then sell here at lower prices when Kentucky does need the power. According to EPSA, the ECAR region needs to add about 5,000 MW of generation per year through 2005 to maintain its current 12 percent reserve margin.[44]

EPSA states that having larger numbers of competitive power suppliers in the market will cause rates to be lower.[45] EPSA believes regulated utilities should not build additional power plants because merchant plant developers are ready, willing and able to build power plants where needed at no risk to ratepayers. EPSA believes that utilities should leave the generation business, be responsible for transmission and distribution service, and let merchant plant developers be responsible for generation.[46]

LG&E/KU state that they give consideration to buying from merchant plants as part of their resource mix and point to the fact that firm power purchases were utilized to meet their native load in each month during 1999 and 2000.[47] LG&E/KU have determined that currently there are lower cost options available than purchases from

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[44] Id. at 14-15.

[45] Id. at 16.

[46] Id. at 24.

[47] LG&E/KU response to Item 3 of the data request included in the Commission's July 2, 2001 Order. The purchases were from EEI, OVEC, and Owensboro Municipal.

merchant plants since such purchases are at market-based prices.[48] LG&E/KU's resource plan includes new CTs and DSM programs to meet demand growth over the next several years. LG&E/KU state that they prefer construction of generation to purchased power if all variables, including total costs, generation availability, and transmission, are equal.[49] However, since consideration of purchased power is an appropriate aspect of resource planning, LG&E/KU believe the Commission should not limit utilities' level of reliance on purchased power. LG&E/KU realize, however, that since conditions are dynamic, a utility's reliance on purchased power must be examined on a case-by-case basis.[50]

At this time, AEP-KY has determined that it should rely on market purchases rather than add new capacity.[51] AEP-KY states that under its prospective three-member power pool, the output from its Big Sandy generating station and its anticipated market purchases will be more than adequate to meet its future load.[52] As with LG&E/KU, AEP-KY recognizes purchased power as an appropriate planning tool and recommends that no limits on purchased power be imposed.[53]

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[48] Bellar prefiled testimony at 4-5.

[49] Id. at 7.

[50] Id. at 6.

[51] Transcript of Evidence, September 19, 2001, at 111.

[52] AEP-KY brief at 7.

[53] Id. at 2 and 8.

East Kentucky has just added two CTs at its J.K. Smith site and has been granted a certificate to construct a 270 MW clean coal unit at its Spurlock Station. It has also contracted with an independent power producer, KPE, to purchase the entire output of a proposed 540 MW merchant plant, which, if built, will likely obviate East Kentucky's need for the new unit at the Spurlock Station.[54] In addition, East Kentucky has contracts with various energy suppliers to purchase capacity during both summer and winter peak seasons while its new generation is under construction.

The AG states that most of the merchant plants being built in Kentucky will sell their power outside the state. Under these circumstances, the AG does not see that new merchant plants constructed in Kentucky would necessarily benefit Kentucky's jurisdictional retail customers.[55]

It is clear from the record that the jurisdictional utilities give serious consideration to purchased power in developing their resource plans. In fact, most of the utilities have historically purchased power and include some level of purchased power in their current plans to serve native load. Hence, although the utilities' IRPs include little discussion of specific merchant plants being constructed or proposed in Kentucky, there is no question that the existence of a strong wholesale market figures prominently in their plans.

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[54] Brown-Kinloch testimony at 8.

[55] Transcript of Evidence, October 1, 2001, at 26.

Last year, the Commission was concerned with the significant increases in prices of natural gas and the overall volatility of wholesale gas markets. The Commission initiated an administrative case[56] and directed the state's five largest gas distribution utilities to take steps to mitigate price volatility. The volatility of electric prices experienced in California and other western states was one aspect of the issues we considered in initiating this proceeding. In presentations before the Energy Board, owners and developers of merchant plants indicate that the existence of these plants will lower market prices. While merchant plants may be able to sell power at prices below the prices of utilities in states where electric prices are high, there has been no evidence provided to show that merchant power will lower the price of energy available to Kentucky utilities and their ratepayers. Further, there has been no evidence provided to show that market prices will be below the cost-of-service rates presently enjoyed by Kentucky's electric consumers.

Further, one of the factors that must be seriously considered when analyzing whether to purchase power from a merchant plant, a power marketer, or broker, is the financial integrity of the seller. The nation's largest volume power marketer, Enron, has recently come under intense scrutiny due to its accounting practices. In less than two

[56] Administrative Case No. 384, An Investigation of Increasing Wholesale Natural Gas Prices and the Impacts of Such Increases on the Retail Customers Served by Kentucky's Jurisdictional Natural Gas Distribution Companies. Order dated September 12, 2000.

months its stock has collapsed and it has filed a petition in bankruptcy.[57] Whether those who purchased power under fixed price terms will see their contracts honored is now unknown. This clearly presents an additional risk not typically associated with utility-constructed generation.

The Commission recognizes that merchant plants can offer a viable option to constructing new regulated generation. However, the prices at which merchant power will be sold will be dictated by regional, or national, markets that respond to many factors that may differ from the factors impacting Kentucky. Accordingly, the Commission is concerned that over-reliance on volatile power purchases at prices established by these markets could lead to higher prices for Kentucky ratepayers.

The Commission believes that its jurisdictional utilities should secure sufficient power to serve native load either through direct ownership of generation or firm power purchases at fixed costs (generally subject to the variability of fuel costs), or a combination thereof, that guarantee performance and reasonable price stability. And as regulated utilities, it is the utilities' responsibility to determine their least cost options. If merchant plants are willing to sell firm power at fixed prices that are lower than the cost to produce electricity with utility-owned generation, the Commission will expect

[57] According to "Utility Spotlight", December 3, 2001, Enron's stock declined from $90 per share in August 2000 to 48¢per share on November 29, 2001.

Kentucky’s utilities to buy, rather than build, all other factors, including a risk assessment of the potential seller, being equal.

Scheduled Maintenance

In addition to providing information on capacity additions, the six jurisdictional utilities provided information on planned capacity retirements, forced outages, and scheduled maintenance. The issue of the utilities coordinating the scheduled maintenance of their generating units was also discussed.

The utilities do not formally coordinate their maintenance schedules with those of other utilities with which they are interconnected. Future maintenance schedules are reported to ECAR on a unit-by-unit basis for a 4-week period. ECAR then issues the utilities a weekly report on the aggregate generation scheduled to be out of service. By this process, utility-specific data is kept confidential to avoid influencing market power prices. Also, in an effort to minimize any negative impact on reliability, the jurisdictional utilities attempt to schedule maintenance during periods of low demand and low market prices, generally in the spring and fall seasons. In addition, TVA provides generator and line maintenance outage schedules to Big Rivers because of the physical proximity of their systems.

According to LG&E/KU, once the Midwest Independent System Operator (“Midwest ISO”) becomes operational it will approve and coordinate the generation maintenance schedules for all its members. Presumably, the Alliance RTO and any public power RTO will do the same. According to Big Rivers, the lack of coordination should not present a problem because each of the six jurisdictional utilities is responsible for meeting native load and maintaining reserves sufficient for system reliability in case of forced outages. However, the notable increase in the volatility of wholesale market electric prices gives the Commission much more reason to be concerned about this lack of coordination. While there may be some future coordination among members of specific RTOs, the prospect of there being two or more RTOs in Kentucky points to the potential for adverse impacts on the reliability of one or more of Kentucky's jurisdictional utilities in the absence of coordination among individual utilities. Therefore, the Commission will require the major jurisdictional electric utilities to conduct a joint investigation of this issue in order to determine actions appropriate to both maintain and enhance service reliability during periods of scheduled maintenance. A joint report summarizing this investigation and the conclusions reached should be filed no later than July 1, 2002.

TRANSMISSION – DISCUSSION

Historical Design and Function of the Transmission System

Electric restructuring has resulted in tremendous changes throughout the industry, particularly with respect to electric power transmission. Historically, each utility's transmission system was designed and built to deliver power efficiently over relatively short distances from its regulated generating facilities to its native load. Adjacent utilities would then interconnect their individual transmission systems to take advantage of load diversity[58] and to provide assistance to one another in times of

[58] Load diversity reflects the fact that customers' electricity usage varies, depending upon the time of day, season, etc. Consequently, utilities may reach peak

emergencies. As municipal utilities and rural electric cooperatives developed and built electric distribution lines to serve more customers, rather than build their own generating resources, they often found it more efficient to either purchase power from other utilities or jointly develop generating resources. This necessitated the construction of more extensive transmission lines between generating units and the areas in which the electricity was consumed. Regulation of the transmission system was divided between the state commissions and FERC, with the state commissions regulating the rates and service provided to end-use customers, referred to as retail services, while FERC regulated wholesale rates and service, generally those services provided between utilities.

New Requirements Arising from FERC Order 888 and Restructuring

Electric restructuring requires a fully functioning, competitive wholesale market for power. Since the buyers of power may be located hundreds of miles from the sellers, it is essential to prevent the operator of transmission facilities, which are still a regulated monopoly, from disrupting a competitive power sale. Thus, FERC Order 888 required all investor-owned utilities to make their transmission systems available to all users on a nondiscriminatory basis.

Second, the existence of individual transmission tariffs by each transmission utility resulted in generation owners having to make separate arrangements with each

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usage at different times from one another. For example, some utilities may reach peaks in the summer (LG&E/KU), others in the winter (AEP-KY and East Kentucky). More efficient use of generating units are achieved if utilities take advantage of these differing peaks and trade power during those times.

transmission owner. This resulted not only in difficulties associated with having to make transactions with possibly several transmission owners in order to get generation to its eventual destination, but also in having to make separate transmission payments to each one, which is referred to as “rate pancaking.”

Third, is the fact that electricity takes the path of least resistance which may or may not reflect the “contract path” between the generator and transmission owners. For example, a generator in Ohio wishing to export power to Tennessee might need to contract with Cinergy, LG&E/KU, and TVA for transmission services. This would result in transmission rates assessed by each utility, one on top of the other or pancaked. In reality some of the power might actually flow through East Kentucky’s or Big Rivers’ transmission systems, who are not parties to the contract and would receive no compensation. This is described as “parallel flows.”

Fourth, and perhaps most importantly for Kentucky, is that transmission systems in Kentucky were not designed to move large amounts of power through the state, and attempting to do so could threaten reliability or overload the transmission systems. The North American Electric Reliability Council has established TLR procedures to prevent dangerous overloads from occurring. Briefly, the TLR procedures require that transactions be curtailed to reduce loading within the capability of the limiting facility. The order in which curtailments are made reflects the duration and "firmness" of the transmission reservation. Generally, the order is to first curtail short-term non-firm, then long-term non-firm, then finally firm and native load/network transactions.

Development of Regional Transmission Organizations

FERC's solution to these problems is to require the establishment of RTOs which envision transmission owners transferring operational control of their transmission systems to a regional entity regulated by FERC. RTOs would theoretically provide open, non-discriminatory access to the transmission system which would: eliminate difficulties associated with transacting with several transmission owners; eliminate rate pancaking by providing service through a single tariff; compensate transmission owners for parallel flows; and improve reliability through regional transmission planning.

In response to FERC's RTO requirements, several utilities in the Midwest began to establish the Midwest ISO. All of Kentucky's jurisdictional utilities were involved in the early developmental efforts. In addition, various stakeholder groups were encouraged to participate, including state commissions. Accordingly, this Commission became involved almost 5 years ago.[59]

Several highly contentious issues were discussed by the Midwest ISO, such as cost-shifting and revenue distributions among utilities. One of the Commission's major objectives was to ensure that any costs added to Kentucky customers through an RTO were offset by benefits from the RTO.[60] Since states with high cost generation could

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[59] The Commonwealth of Kentucky, along with Iowa and Illinois, are the state representatives on the Midwest ISO Advisory Committee (Kentucky is the senior state representative). This committee, which Kentucky will be leading in 2002, includes all relevant stakeholder interests and advises the Midwest ISO Board.

[60] It is the presumption that an RTO will provide more reliability for a region. This Commission questions the benefits versus the costs of RTOs and has asked FERC to study this issue.

likely receive some benefit from being able to access lower cost generation, they could justify the additional costs that an RTO might add. However, that did not appear to be the case in Kentucky, since we already had the lowest rates in the region. Not only did the RTO administrative costs pose an additional cost burden but the mere existence of a regional rate-setting mechanism also provided an opportunity to shift the responsibility for the cost of transmission investment among utilities. While the Commission supported a regional rate-setting mechanism to help compensate affected utilities for parallel flows, we were adamant that this mechanism not be used to shift costs among utilities without clear cost justification. The Midwest ISO's configuration has gone through numerous changes since that time but currently extends from Manitoba, Canada to Kentucky and from South Dakota to Virginia. The Midwest ISO is expected to be partially operational by December 15, 2001. Of Kentucky's jurisdictional utilities, only LG&E/KU have become members of the Midwest ISO. ULH&P owns no transmission facilities, but its parent, CG&E does and it has also joined the Midwest ISO. AEP-KY has joined another RTO, known as the Alliance RTO. East Kentucky and Big Rivers are currently in discussions with TVA to form a public power RTO.[61]

TRANSMISSION ADEQUACY

A utility's transmission adequacy can be viewed from the perspective of its ability to serve native load and its ability to accommodate bulk power transfers while maintaining system reliability. The utilities have stated that their existing transmission systems are currently adequate to serve their native load. They state that reliability concerns are caused by bulk power transfers and that currently those concerns are handled by the NERC TLR procedures in conjunction with each utility's individual operating procedures. Since each utility's transmission system was planned to accommodate its existing and projected native load, there is only limited capacity available to accommodate bulk transfers. Consequently, in recent years some transactions have had to be curtailed to protect the integrity of the transmission system.

Description of Kentucky's Transmission System

The following is a brief discussion of each utility's transmission system. The systems can generally be described as low voltage, subtransmission systems with relatively few high voltage interconnections.

The Big Rivers transmission system is interconnected with five neighboring control areas at multiple locations. It has one interconnection with Hoosier Energy, two

[61] TVA and the Midwest ISO have entered into a memorandum of understanding to address issues of common interest.

with LG&E/KU, one with Sigeco, two with SIPC, seven with TVA, and six with HMP&L. Except for a 345 kV route that connects the Coleman-Wilson-Reid generating stations, its system is primarily at voltages of 161 kV or lower.

AEP-KY is part of a multi-state power pool. Its transmission system is more highly interconnected with affiliates in other states than with other transmission systems in Kentucky. AEP-KY's transmission system generally consists of circuitry operating at 138 kV and lower voltage with the exception of two 765 kV lines that are interconnected with affiliates in neighboring states.

LG&E/KU's transmission system, operated as a single control area since the merger of LG&E and KU in 1998, is comprised of approximately 546 miles of EHV lines, 1,881 miles of 138 kV and 161 kV lines, and 2,735 miles of 69kV and below. These lines connect to 47 major transmission substations and 14 generating stations, and the system is interconnected with eight neighboring utilities.[62] There are 47 East Kentucky distribution substations supplied through either KU or LG&E transmission and 16 KU distribution substations supplied through East Kentucky. TVA has 6 distribution substations supplied through KU transmission and KU has 1 distribution substation supplied through TVA.

ULH&P's transmission system is a low voltage system with two connections to CG&E's 138 kV transmission system and two connections to CG&E's 69 kV

[62] American Electric Power, Big Rivers Electric, Cinergy, East Kentucky, Electric Energy, Inc., Ohio Valley Electric, Southern Indiana Gas & Electric, and TVA.

transmission system.[63] It can be characterized as a subtransmission system. As a result, the ULH&P transmission system has a very low response to energy transfers that occur throughout the region; therefore, transfers occurring across the region have very little effect on ULH&Ps transmission system.

As previously noted, East Kentucky is heavily interconnected with KU. It has five interconnections with AEP, one with CG&E, and six with TVA. Like Big Rivers, except for a 345 kV route that connects Spurlock-Avon-J.K. Smith generating or substations, its system is also primarily lower voltage.

Kentucky System Reliability Concerns

LG&E/KU noted that their joint transmission system is adequate to serve existing transmission requirements in Kentucky. LG&E/KU stated that they will continue to upgrade their transmission system to service their native load and to satisfy their obligations to provide transmission service under FERC requirement, to the extent necessary and to ensure the continued delivery of reliable electric service. However, LG&E/KU have no planned additions to increase export capability or to relieve parallel flow problems.

The only known "bottleneck" in AEP's system that could have an impact upon reliability to Kentucky transmission customers involves the potential overload of the 345 kV circuit between the Kanawha River Station in West Virginia and the Matt Funk

[63] There are also two connections with East Kentucky, but these are normally open and are used primarily for local transmission support during transmission outages.

Station in Virginia. The outage of 765 kV facilities could result in thermal overloads and low voltages in the Kanawha River-Matt Funk area and on underlying transmission networks which therefore could impact service reliability of AEP's native load customers in Kentucky. The availability of spare equipment and the use of established operating procedures can help to minimize the adverse effects of these and other unplanned outages of critical facilities.

AEP has been seeking approvals to build a 765 kV line from the Wyoming Station in West Virginia to the Jackson's Ferry Station in Virginia since 1991 to address this potential constraint.[64] The Kentucky reinforcement project included construction of a 138 kV line in Kentucky between Big Sandy Station and the Inez Station and installation of a Flexible Alternating Current Transmission System ("FACTS") device at Inez Station.[65]

Big Rivers also noted problems with parallel flows. According to Big Rivers even when the parallel flow is only a small percentage of total flow, it can still overload various sections of the Big Rivers transmission grid in Kentucky. The only engineering solution to these overloads is to build more transmission facilities. However, more transmission facilities would facilitate even greater parallel flows without generating any additional revenue for Big Rivers.

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[64] This project has been somewhat controversial in that national forest land is involved.

[65] This project was approved by the Commission by Order dated June 11, 1996 in Case No. 95-403.

East Kentucky indicated that it has an adequate, reliable transmission system to serve its native load, but during the last 2 years, heavy north to south transfers have stressed its system.[66] East Kentucky cited specific problems in the past 2 years relating to bulk power transfer. East Kentucky identified three transmission facilities that frequently cause problems:

1. LG&E Blue Lick 345/161 kV transformer
2. LG&E Blue Lick - East Kentucky Bullitt County 161 kV line
3. KU Ghent - KU West Lexington 345 kV line

East Kentucky described several instances where actions appear to be routinely taken to avoid overloading these facilities. These actions generally take the form of opening a breaker, which helps to reduce the loading, but this results in losing a two-way feed to one or more substations or eliminates East Kentucky's tie to LG&E or TVA. To date, sectionalizing these lines has not caused outages or substandard service, but operating with these lines open puts East Kentucky closer to the edge and will ultimately result in outages or low voltages. The loading problems on KU's Ghent to West Lexington line appear to be more difficult to resolve since there are currently no local operating procedures to reduce this loading. This has not reduced East Kentucky’s reliability, but the potential exists for limiting East Kentucky's ability to import capacity.

The Owensboro Municipal system has experienced overload problems due to outside system flows that have resulted in reduced generation output to alleviate the

[66] Atchison testimony at page 2.

loading levels. There were two specific instances in January and February 2001 where system flows through the Elmer Smith Station 138/345 kV transformer have caused a reduction in generation resulting in lost revenues to Owensboro Municipal. In general terms Thoroughbred Generating notes that the Kentucky transmission system is weak in the interconnections to utilities south of Kentucky and this inhibits north to south flows. There are only two interconnections with TVA above 161 kV and the Kentucky to TVA transmission path is regularly the limiting element for north to south flows.

The transmission study referred to later in this Order confirms that the transmission system in Kentucky is adequate to serve native load. The electric flow analysis model's base case evaluation performed in the study indicates that there are no overloaded transmission facilities in Kentucky for the projected Summer 2005 Peak load condition.[67]

<u>Transmission Study</u>

<u>Task Force, ECAR Model, Commonwealth Associates Review</u>. In response to Executive Order 2001-771, Commission Staff conducted an engineering evaluation on the impact that the proposed generating facilities would have on the electric transmission system in Kentucky.[68] This study revolved around a computerized electric flow analysis model, which performed under the Staff's direction by utility engineers.

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[67] There is one TVA transformer located in Tennessee that is loaded to 101 percent of its rated capacity in this case.

[68] The proposed generating facilities are listed in Table 1 on p. 60.

The model was reviewed and expanded by Commonwealth Associates, Inc. (“CAI”), an independent electrical engineering consultant. The study is attached as Appendix J to this Order.

The model was created by a task force consisting of transmission engineers from each jurisdictional utility, TVA and Staff. This task force acquired the East Central Area Reliability Coordination Agreement[69] (“ECAR”) 2005 Summer Peak transmission model.[70] The model was updated to reflect the utilities’ most recent known data and the power plants proposed for construction in Kentucky were inserted. The power plants were grouped geographically, as shown in Table 1 on page 64, for study purposes. See also Map 9 in Appendix H to this Order. The task force included 24 proposed power plants that were not affected by Executive Order 2001-771. The Cinergy - Silvergrove plant directly serves an industrial customer and does not put

[69] ECAR is one of the 10 regional reliability organizations that comprise the North American Electric Reliability Council (“NERC”). NERC is a voluntary organization responsible for promoting electric system reliability. Kentucky is part of both the ECAR and SERC regions.

[70] This model was selected because it was the latest year for which projections were currently available and provided a reasonable time frame in which proposed generation could be completed. The ECAR model is compiled from information submitted to the FERC by each utility and is universally accepted and used in the industry for transmission planning. The utility industry under the auspices of the reliability councils (ECAR is one), NERC, and FERC provide transmission data and updates on a yearly basis to build models of the bulk power transmission grid. This is an important and tremendous undertaking that results in very accurate models of the entire interconnected transmission systems in the U.S. These are the best and only models available for undertaking a study of this nature.

power onto the transmission system so its output was not included in the model. Three of the plants: Kentucky Pioneer Energy, Thoroughbred Generating, and Dynegy-Riverside were each modeled as two plants at the same site.

Table 1
Proposed Generation Capacity and Locations

	Summer			**Transmission**
Plant Name	**MW**	**County**	Fuel Type	**Connection**
Global – KY Pioneer Energy	334	Clark	Coal/Refuse	EKPC – JKSmith 345 kV
Global – KY Pioneer Energy	167	Clark	Coal/Refuse	EKPC – JKSmith 138 kV
EKP – JK Smith	240	Clark	Nat. Gas	EKPC – JKSmith 138 kV
EKP – Spurlock	270	Mason	Coal	EKPC – Spurlock 345 kV
Calla – Estill	110	Estill	Waste Coal	LGEE - W. Irvine 161 kV
Case 100 New Generation	1121			
Enron – Calvert City	540	Marshall		TVA – Benton 500 kV
EnviroPower - KY Western Power	500	Marshall	Coal	TVA – Benton 500 kV
Duke – Marshall County	640	Marshall		TVA – Marshall 161 kV
Air Products and Chemicals	30	Marshall		TVA - Calvert 161 kV
Westlake Energy	520	Marshall		BREC - Livingston 161 kV
PG&E – La Center	105	Ballard		LGEE - Grahvl 161 kV
Case 200 New Generation	2335			
Duke – Metcalfe County	640	Metcalfe		TVA - Summershade 161 kV
PG&E – Summer Shade	105	Metcalfe		LGEE - Summershade 161 kV
Case 300 New Generation	745			
Columbia – Crane Creek	480	Henderson		BREC - Reid 345 kV
Cash Creek	1000	Henderson		LGEE - Smith 345 kV
Thoroughbred	750	Muhlenberg		BREC - Wilson 345 kV
Thoroughbred	750	Muhlenberg		TVA - Paradise 500 kV
Dayton P&L – Hardinsburg	400	Breckenridge		BREC - N.Hardinsburg 161 kV
Case 400 New Generation	3380			
LG&E – Paddy's Run	151	Jefferson		LGEE - PaddysRun 138 kV
Dynegy – Bluegrass	501	Oldham		LGEE - Bucknr 345 kV
LG&E – Trimble Co	1002	Trimble		LGEE - Trimble 345 kV
Cinergy – Erlanger	84	Kenton		CIN – Earlanger 138 kV
Cinergy – Silvergrove	0	Campbell		CIN - Withdrawn - Not Modeled
Case 500 New Generation	1738			
EnviroPower - KY Mountain Power	500	Knott		AEP - 3-138 kV near Beaver Ck
Dynegy – Riverside	501	Lawrence		AEP - Baker 345 kV
Dynegy – Riverside	501	Lawrence		AEP - Baker 345 kV
EnviroPower - KY Eastern Power	500	Martin		AEP - Inez 138 kV
Case 600 New Generation	2002			
Total	11321			

Model – Base Case. The task force established the base case for this study by setting all the proposed generating units in the model to zero output, except where needed to serve native load. This case did not identify any overloaded facilities in Kentucky and this indicates that the existing transmission system is capable of serving the native load under normal operating circumstances.

Model – Second Case. The second case assumed that all of the 24 proposed plants are constructed and operate at full capacity. As generation and load must be balanced at all times, turning the new generators "on" means either that demand is increased or another generator is turned off resulting in a model that has generation equal to load. Rather than increasing demand in Kentucky, the model assumed that the additional generation would be exported by lowering generation outside of Kentucky.

It was assumed that generation would be exported south, which reflects historical flows under system peak conditions. Accordingly, the generation was assumed to be exported to the following areas in the specified percentages: Florida 22 percent, Southwest Power Pool 20 percent, SERC-EQ 38 percent and Entergy 20 percent. It should be noted that this is a very significant assumption. However, in the absence of specific information regarding the markets expected to be served by the new generators, it was necessary to make these assumptions.

Reliability refers to a system's ability to deliver power of adequate quantity and quality. To maintain reliability, transmission systems "need to plan Bulk Electric Systems that will withstand adverse credible disturbances without experiencing uncontrolled interruptions" and the "importance of providing a high degree of reliability for local power supply but the impossibility of providing 100 percent reliability to every customer or every local area."[71] Consequently, simulated reliability testing involves simulating credible disturbances or outages of important facilities, referred to as "contingencies," to estimate the effect of the outage on the transmission system. Typically, the transmission system is designed to operate reliably with any random generation and transmission line outage. In this situation, generation outages were not simulated given the nature of the problem being studied - the effect of excess generation on Kentucky's transmission system.

Single contingencies of facilities 100 kV and above were simulated in AEP, Big Rivers, Cinergy, East Kentucky, LG&E/KU, and TVA territories. Overloads that could easily be corrected were identified by the utilities, and the model was updated to reflect these corrections.[72]

This case revealed several overloaded facilities. It should be noted that these overloads identified in this case reflect an outage on another facility, but NERC Operating Policy and good utility practice prohibit scheduling more power over the system than indicated by the first contingency transfer capability.

[71] ECAR Document No. 1, Reliability Criteria for Evaluation and Simulated Testing of the ECAR Bulk Electric Systems.

[72] As an example, a conductor might not be listed at its full rating because of inadequate clearances. The changes made to the model assumed that the clearance would be altered so that the maximum rating of the conductor would be reflected and were limited to uprating to full conductor ratings.

Map 11 in Appendix H to this Order highlights existing facilities that the model indicates would overload if all proposed generation were running during the Summer 2005 Peak condition.

The proposed generation was then reduced to relieve the facility overloads. Table 2 on the next page gives the maximum generation values that each proposed generator could produce under the given conditions without overloading the transmission system. The table indicates two values of generation the "task force" column and the "CAI" column. In CAI's review, they modeled the system but included additional improvements to the existing transmission system. (The cost figures listed in Table 2 are intended to indicate the order of magnitude of the costs of the assumed upgrades. There was no detailed study of actual improvements necessary to relieve overloaded facilities.)

Table 2 also indicates that for the Summer 2005 peak demand conditions, the transmission system can accommodate between 6,000 and 7,800 MW of the additional 11,300 MW of generation currently proposed in Kentucky without major transmission improvements. It must be noted that the results would vary with any changes in the assumptions, such as the location of the additional generation, the quantity of additional generation, or the location of the demand. The study does not include transmission improvements that may be constructed in conjunction with the additional generators even though CAI's study results incorporate several minor improvements.

Table 2 – Proposed Generation Supported by the Transmission Grid

		Plant	Maximum Output[1]	
		Capacity	Task Force Model	CA1 Model
Proposed Plant Name	County	(MW)	(MW)	(MW)
Case 100 – Central KY[2]				
Global – KY Pioneer Energy	Clark	334	334	334
Global – KY Pioneer Energy	Clark	167	0	167
EKP – JK Smith	Clark	240	90	240
EKP – Spurlock	Mason	270	270	270
Calla – Estill	Estill	110	110	110
Total		1121	804	1121
Case 200 – Purchase Area[3]				
Enron – Calvert City	Marshall	540	0	208
EnviroPower – KY Western Power	Marshall	500	0	193
Duke – Marshall County	Marshall	640	0	247
Air Products and Chemicals	Marshall	30	30	12
Westlake Energy	Marshall	520	340	200
PG&E – La Center	Ballard	105	105	40
Total		2335	475	900
Case 300 – South-Central Kentucky[4]				
Duke – Metcalfe County	Metcalfe	640	0	640
PG&E – Summer Shade	Metcalfe	105	0	105
Total		745	0	745
Case 400 – Western Kentucky				
Columbia – Crane Creek	Henderson	480	0	0
Cash Creek	Henderson	1000	190	190
Thoroughbred	Muhlenberg	750	80	80
Thoroughbred	Muhlenberg	750	750	750
Dayton P&L – Hardinsburg	Breckinridge	400	245	245
Total		3380	1265	1265
Case 500 – N. Kentucky / Louisville[5]				
LG&E – Paddy's Run	Jefferson	151	151	151
Dynegy – Bluegrass	Oldham	501	290	501
LG&E – Trimble Co	Trimble	1002	1002	1002
Cinergy – Erlanger	Kenton	84	84	84
Cinergy – Silvergrove	Campbell	0	0	0
Total		1738	1527	1738
Case 600 – Eastern Kentucky				
EnviroPower – KY Mountain Power	Knott	500	500	500
Dynegy – Riverside	Lawrence	501	501	501
EnviroPower – KY Eastern Power	Martin	500	500	500
Total		2002	2002	2002
Grand Total Generation		11321	6073	7771

[1] CAIs review assumes several additional transmission improvements than did the task force.
[2] CAI included an upgrade to a transformer. Approximate cost is in the magnitude of $5 million.
[3] CAI included an upgrade to a 161 kV line. Approximate cost is in the magnitude of $1-5 million.
[4] CAI included an upgrade to several 161 kV lines. No estimate.
[5] CAI included an upgrade to a transformer. Approximate cost is in the magnitude of $5 million

The Summer 2005 Peak condition was chosen for evaluation because most utility generation is running and committed to serve existing load and this cannot be dispatched to relieve the overloaded facilities. Therefore, under the peak condition there are fewer options to maintain reliability short of shedding load.

CAI's Discussion of the Kentucky Transmission System. While the scope of the study did not include a determination of transmission improvements needed to increase the capability of the transmission system to accommodate the 24 additional plants, and further study would be needed to determine appropriate transmission improvements, CAI made the following observations in their report:

> One general observation is that the existing extra high voltage (EHV) transmission grid in Kentucky is not integrated into a grid arrangement. There are several instances where the EHV transmission lines terminate at a substation serving lower voltage transmission lines.[73] The transfer capability across the system would be enhanced if the EHV lines were better interconnected together.
>
> From the EHV transmission grid perspective, Kentucky truly is the border between the north and the south. EHV transmission is designed to move large blocks of power (i.e., 500 MW or more) long distances. The standard transmission voltages used for the EHV grid are 345 kV, 500 kV and 765 kV. Typical capabilities for EHV transmission lines are:
>
> 345 kV - about 1000 MW
> 500 kV - about 2000 MW
> 765 kV - about 3000 MW
>
> Kentucky is bordered on the south by the TVA power system, which uses 500 kV transmission. There are three 500 kV lines in Kentucky that tie to the TVA system. Kentucky is bordered on the north by several utilities, all of which use 345 kV EHV transmission. There are eight 345 kV transmission interconnections to the northern utilities. On

[73] See Map 12, Kentucky's standard transmission voltage vary from North to South.

the far eastern parts of Kentucky, AEP has a strong 765 kV EHV grid comprised of one 765 kV from Kentucky to Virginia, one to West Virginia, and one to Ohio.

There are three EHV north-south transmission paths across Kentucky:

1. TVA Shawnee-Marshall-Benton-Cumberland 500 kV. The Cumberland 500 kV substation is located in Tennessee. This path is rated 1735 MVA and is located in the far western portion of the state.

2. LGEE Ghent-W. Lexington-Brown-Pineville 345 kV and Pineville-Pocket 500 kV. The Pocket 500 kV substation is located in Virginia and connects to TVA at Phipps Bend, Tennessee. The path is rated approximately 500 MVA and is limited by the 345-500 kV transformer at Pineville. This path is approximately center of the state.

3. AEP Hanging Rock-Baker-Broadford 765 kV. The Broadford 765 kV substation is located in Virginia. A 500 kV line extends from Broadford to TVA at Sullivan substation in Tennessee. The 765 kV Baker-Broadford line is rated 4174 MVA and the 500 line to TVA is rated 1710 MVA. This path is located in the far eastern portion of the state.

There are three EHV east-west transmission paths across Kentucky:

1. LGEE Smith-Hardinsburg-Brown 345 kV. This east-west transmission path is in the center of the state and has its eastern termination at the north-south Ghent-W. Lexington-Brown-Pineville 345 kV path mentioned above. Its western termination is into the lower voltage transmission grid. The Smith-Hardinsburg 345 kV line is rated 1195 MVA and the Hardinsburg-Brown, 717 MVA.

2. AEP Hanging Rock-Jefferson 765 kV. The AEP Hanging Rock-Jefferson 765 kV line interconnects the AEP 765 kV transmission system in western Kentucky with the AEP system in southern Indiana.

3. OVEC Pierce – Clifty Creek double circuit 345 kV. Pierce 345 kV substation is in Ohio and Clifty Creek is in Indiana. The OVEC Pierce-Clifty Creek double circuit 345 kV line crosses the extreme northern portion of Kentucky.

Both the AEP Hanging Rock-Jefferson 765 kV line and the OVEC Pierce-Clifty Creek double circuit 345 kV line cross northern Kentucky but do not have a connection to the lower voltage transmission in Kentucky. Only the LGEE Smith-Hardinsburg-Brown 345 kV line directly interconnects with the underlying 161 and 138 kV transmission serving central Kentucky loads.

The EHV transmission grid services a 161 and 138 transmission system. The TVA and southern portion of Kentucky is comprised of 161 kV transmission, whereas, the northern portion of Kentucky is 138 kV. The result of having two different voltages is that it is more difficult and expensive to interconnect the grids. A substation and transformer is required where the 138 and 161 kV transmission systems are interconnected, and similarly where the 345 and 500 kV EHV systems are interconnected. The substations and transformers are expensive to build and also serve as a bottleneck to the flow of power between systems.

In conclusion, the EHV transmission and the underlying 161 and 138 kV transmission in Kentucky are not strongly interconnected and, therefore, limit the power transfer capability from north to south or east to west across the state. The addition of key EHV transmission lines could be added to make a much stronger transmission grid.[74]

[74] Kentucky Transmission System Evaluation, Commonwealth Associates Inc, Dec. 2001, Volume 1, Page 1-3.

TRANSMISSION ISSUES

Merchant Plant Transmission Additions and Cost Recovery

The rates and rules for interconnecting a merchant plant to a utility's transmission system are under FERC's jurisdiction. FERC has historically required the merchant plant to pay the utility for the cost of any transmission improvements needed to make the interconnection. Although this is still FERC's policy, there have been some advocates for allowing the additional costs to be recovered from all transmission users. FERC currently has under consideration an advance notice of a proposed rulemaking on standardized interconnections and may subsequently address the rate issue.[75]

The process for interconnecting merchant plants to the transmission system is similar for each utility. Generally, the merchant plant requests a system impact study that provides an initial estimate of the cost to connect the merchant plant to the system, as well as an estimate of the costs of system expansions required. After review of this initial study, if the merchant plant still wants to pursue the project, more detailed studies would be performed and, ultimately, an interconnection agreement would be reached. The costs of all studies and all necessary transmission upgrades would be borne by the merchant. In return for paying the cost of transmission upgrades, the merchant plant receives service credits equal to the cost paid.

There is no existing mechanism for reimbursing the incumbent utility for the costs of transmission upgrades needed to relieve constraints resulting from parallel flows. This is because there is no contract covering the parallel flow. This is expected to change once RTOs are in operation and should result in assignment of costs to the cost-causer.

East Kentucky is concerned that increasing Kentucky's capability to eliminate transmission problems stemming from parallel flows and bulk wholesale transactions will require significant investments by the utilities in the Commonwealth and will have to be paid by native load customers. Since wholesale power transactions by third parties are the primary cause of transmission problems, it would be unfair to require native load customers to bear the cost of the investment required to resolve these problems.

Thoroughbred Generating is concerned that while Kentucky's transmission system may be planned to reliably serve native load, it is not being upgraded at a pace that will accommodate the continued delivery of low cost power to Kentucky customers while allowing the Commonwealth to reach its economic potential as an energy exporter.[76] Thoroughbred Generating suggests that changes in the electricity industry have created uncertainties over responsibilities and have led transmission providers to analyze their transmission system from strictly a reliability and ability to serve native load basis, which is essentially a technical review. It advocates that transmission system planning should also weigh the potential economic benefits of increasing

[75] FERC Docket No. RM02-1-000.
[76] Williams testimony at 5.

transmission to provide low cost energy to customers and to allow export of energy to other states and regions.[77]

The AG states that each transmission problem must be dealt with on a case-by-case basis. He suggests that the Commission should investigate each problem to determine the least cost solution and then authorize needed construction and assign the costs based on the expected benefits.

The Commission concurs with Thoroughbred Generating that potential economic benefits of transmission facilities should be a consideration when approving new construction. However, KRS 278.020(1) prohibits the Commission from certificating the construction of any facilities absent a demonstrable need.

Even if some quantifiable benefit could be demonstrated, it would not serve the public interest to require significant transmission investments in the absence of any firm commitments that this transmission capacity would actually be used. While over 11,000 MW of additional generating capacity has been proposed, it is extremely unlikely that all of this capacity will be built. It would be imprudent for a utility to build additional transmission capacity in the absence of any firm commitment from merchant plants to pay for the additional capacity. We understand there are new technologies that can be added to transmission systems that may significantly increase the throughput of electricity, thereby mitigating the need to add new transmission routes or construct new transmission lines.

[77] Thoroughbred Generating estimated at the hearing that it would cost approximately $100 million in transmission upgrades to serve just its proposed plant.

Furthermore, while the results of the transmission study show that approximately half of the proposed generation can be accommodated by the existing transmission system, that situation is true only at peak times. Merchant plants that the study shows could not be accommodated during peak periods may be able to generate during non-peak periods depending upon where the merchant plants are located and the markets they intend to serve. Thus, a proposed new merchant plant might be able to operate for a substantial number of hours during the year, except at peak periods, by taking non-firm transmission service. Non-firm service has a greater chance of being curtailed in the event of transmission congestion. If a merchant plant wants to operate during the more lucrative peak times, it can do so, but would be required to pay for the additional transmission capacity improvements necessary to handle its generation.

New transmission capacity can be and is being built under existing procedures with the merchant plants paying for the costs of the new facilities. When a merchant plant analyzes where to locate, one of the factors it must consider is the existing availability of transmission capacity. Requiring a merchant plant to pay for the cost of transmission upgrades forces it to make realistic, economic decisions. Deciding how much transmission to build and where is a function of both the planned location of the new merchant plant and the market to be served. If the costs of transmission are socialized and paid by all transmission customers, the merchant plant would have no incentive to accurately declare its most likely intended market, but would instead seek the building of transmission to all possible markets.

Transcript of Evidence at 159-160.

Regional Transmission Organizations

As previously discussed, FERC's solution to transmission problems created by open access and a more robust wholesale electricity market is to require the establishment of RTOs. Following is a brief discussion of concerns related to the establishment of RTOs.

With respect to FERC Orders on RTOs, Big Rivers states that it hopes that RTOs or public power "look alikes" will help solve the region's parallel flow problems. It also states that when parallel flows are viewed as impacting several transmission owners, as opposed to one transmission owner, the problems will be viewed more seriously, and issues concerning receiving compensation as well as a fair allocation will be addressed.[78]

East Kentucky supports the development of RTOs and actively participated in the discussions to organize the Midwest ISO. However, East Kentucky decided not to join the Midwest ISO or any RTO until it could be demonstrated that there were tangible benefits that would offset the cost of joining. East Kentucky is contiguous with the Midwest ISO, the Alliance RTO, and the Public Power Regional Transmission Grid, which are currently under consideration in Kentucky. East Kentucky continues to evaluate its options regarding RTO membership.

ULH&P notes that Cinergy is one of the founding members of the Midwest ISO and is also a leading participant in the discussions between the Midwest ISO and the

Alliance RTO in support of developing a single seamless energy market in the region. Given that RTOs will manage both transmission operations and transmission planning on a regional basis, including functions such as congestion management and security coordination, ULH&P states that RTOs will be responsible for the overall reliability of transmission in their respective regions and will coordinate with each other to promote reliability of the entire grid.

LG&E/KU recommend that this Commission be actively involved in developing FERC policy on the operation of transmission systems on a regional basis and ensuring the equitable allocation of costs for transmission services. LG&E/KU also recommend that the Commission continue its involvement in the activities of the RTOs proposed for the Midwest.

AEP-KY states that the participation of AEP in the Alliance RTO will help to address anticipated transmission constraints over a wide area. It maintains that this approach will facilitate efficient system expansion and also forecast the transmission requirements of native loads connected to the Alliance RTO transmission system.

The AG is not in favor of RTOs, or other regional organizations, making transmission planning decisions. He is concerned that if Kentucky's transmission system is controlled by multiple RTOs, that problems like those noted by East Kentucky may not be addressed if the RTOs cannot agree on who is responsible for correcting them.

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[78] Big Rivers, TVA, and other public power entities in the Southeast including East Kentucky are working to develop agreements, under the auspices of the Public

Gallatin Steel states that FERC Order No. 2000 provides flexibility regarding Commission involvement in RTO matters, and suggests that the Commission play an active role in the formation of any RTO serving Kentucky markets.[79] Gallatin Steel also suggests that the Commission work directly with Kentucky stakeholders to evaluate critical RTO structure, design, operating, and pricing issues.

The Commission will continue to support federal and other states' efforts in this area, but not at the expense of Kentucky customers. However, recent events give us cause for increased concern regarding protections for Kentucky customers. We sought to have bundled, retail load made exempt from the Midwest ISO's administrative costs unless there were off-setting benefits from transmission services provided by the Midwest ISO.[80] FERC recently eliminated this protection which we believed was necessary in order to support participation by our utilities in the Midwest ISO in its Opinion No. 453. Currently, Kentucky customers receive electric service much as they did prior to the formation of the Midwest ISO. Hopefully, this will continue after the Midwest ISO is operational. Once the Midwest ISO begins to provide service to Kentucky customers above and beyond existing service, it would then be appropriate for

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Power Regional Transmission Grid, that will satisfy FERC's RTO requirements.

[79] Goins testimony at page 15.

[80] The argument that the Midwest ISO's potential ability to resolve transmission constraints is a benefit to Kentucky customers ignores the fact that Kentucky customers did not cause the problem. Reliability is cited as a benefit to Kentucky from the development of RTOs; however, reliability was not threatened until federal and regional policies encouraging large, wholesale, bulk-power transfers were developed.

Kentucky customers to bear a reasonable portion of the Midwest ISO's administrative costs.[81]

The Midwest ISO is currently studying the allocation of firm transmission rights and possible future auctioning of such rights. Its guiding principle at present seems to be that firm transmission rights should be allocated to those who paid for the embedded costs of the transmission systems. We believe this is entirely appropriate, but pressure from other stakeholder groups, primarily merchant generators, to eventually transition to auctioning firm transmission rights irrespective of who bore the embedded costs, is cause for considerable concern.

The issue of curtailment procedures, especially the adoption of a pro rata approach, could negate the Commission's efforts to ensure that Kentucky has adequate generation and transmission capacity. If curtailments are made regionally on a pro rata basis, rather than being based on a particular area or state having adequate capacity,[82] utilities would have little incentive to maintain adequate generating capacity, since capacity owned by utilities in other states could be required to serve all areas equally.

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[81] LG&E/KU have requested rehearing of this decision pursuant to an informal agreement reached several years ago.

[82] In view of the potential for defaults under firm power contracts, demonstrating "adequate capacity," such as by tying them to actual generating units, is even an issue, as well as developing a consistent definition of "capacity" to facilitate its use as a financial instrument. This is similar to the common understanding and definitions about "money" which facilitates its use as a common medium of exchange.

Thus, it would be of little benefit to require Kentucky utilities to maintain adequate reserves if curtailments regionally were made on a pro rata basis, since Kentucky customers could be curtailed due to shortages elsewhere. Hence, we support the position that those who have not secured demonstrable generating capacity should be the first curtailed rather than sharing curtailments on a pro rata basis across the entire region.

Potential outcomes on these issues could have a profound effect on Kentucky customers. The Commission will continue to monitor these issues and assert Kentucky's interests, but would welcome participation and assistance from other interested parties. Given the volume of activity at the regional and federal levels, it may be difficult, if not impossible, to accurately evaluate the impact on all Kentuckians; however, the Commission is interested in hearing the concerns of all Kentucky stakeholder groups.

SITING OF GENERATION AND TRANSMISSION

The siting of facilities to be used for the generation or transmission of electricity involves consideration of many issues, of which some are generally thought to be local in nature. These local issues include land-use management and planning and zoning. However, in recognition of the fact that utilities are required to construct facilities to provide adequate and continuous service to the public, KRS 100.324(1) exempts from the requirements of local planning and zoning all service facilities to be located or relocated by a utility operating under the jurisdiction of this Commission or the FERC.

Utilities that operate under the jurisdiction of the Commission must obtain Commission approval before they begin to construct any generating facilities or major transmission facilities, particularly those needed to tie generation into the existing transmission grid. The approval process consists of two separate and distinct analyses arising under different statutory provisions.

One analysis, arising under KRS 278.020(1), requires the Commission to grant a certificate of public convenience and necessity before the proposed facilities are constructed. This analysis examines the extent to which a utility's existing facilities are or will soon be inadequate to provide reasonable service to current or future customers. If an inadequacy exists, the proposed facilities are then examined to ensure that they will not result in any wasteful duplication. In addition, if the proposed facilities include a new transmission line that will operate at 400 kilovolts ("kV") or higher, KRS 278.027 requires consideration of the route of that line. Specifically, the Commission cannot grant a certificate of public convenience and necessity for a 400 kV or higher transmission line unless it finds that the proposed route "will reasonably minimize adverse impact on the scenic and environmental assets of the general area concerned, consistent with engineering and other technical and economic factors."[83]

The other analysis, arising under KRS 278.025, requires the Commission to determine whether the utility should be granted a certificate of environmental compatibility to construct facilities to be used for the generation of electricity. This analysis examines the environmental impacts of the proposed facilities and requires any adverse impacts to be balanced against the community needs, industrial development, customer requirements, and the economics of the facilities.[84]

Historically, a majority of the electric generating facilities and transmission lines built in Kentucky were constructed by utilities operating under the Commission's jurisdiction. Consequently, the overwhelming majority of generating facilities and transmission lines were reviewed and approved by the Commission. Now with the recent proliferation of merchant power plants and the formation of RTOs, the generating facilities and transmission lines constructed by those entities will escape regulatory review by both the Commission and any local planning unit.

Merchant plants and RTOs provide no direct retail electric service to customers in Kentucky. Rather, their transactions in Kentucky are at wholesale, i.e. sales for resale, to utilities, marketers, or brokers. Thus, merchant plants and RTOs are not providing service "to or for the public," as that phrase is used in defining a "utility" under KRS 278.010(3)(a). Consequently, they are not "utilities" under the jurisdiction of the Commission. Accordingly, merchant plants and RTOs are at liberty to construct facilities anywhere in Kentucky without undergoing siting review.

In every instance, the merchant plants operating in Kentucky fall within the definition of "utility" as set forth in the Federal Power Act, and their wholesale rates for power are subject to regulation by FERC. While merchant plants routinely request and receive approval from FERC to sell power at market-based rates, they do operate under

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[83] KRS 278.027.
[84] KRS 278.025(6).

the jurisdiction of FERC. This qualifies merchant plants for the exemption from local planning and zoning under KRS 100.324. However, since the Federal Power Act specifically prohibits FERC from asserting jurisdiction over generating facilities, this leaves the siting of merchant plants totally unregulated in Kentucky at this time.

Similarly, RTOs are engaged in wholesale transactions involving the transmission of power in interstate commerce. Thus RTOs are subject to FERC jurisdiction and are, therefore, exempt from KRS 100.324. It is not now known with certainty whether RTOs will seek to build transmission facilities in Kentucky in their names individually or jointly in conjunction with Commission-regulated utilities. If individually, the construction would be exempt from Commission jurisdiction since RTOs are not utilities under KRS 278.010(3). If jointly, the construction would require Commission approval, but serious questions then arise as to Kentucky's need for facilities to serve the regional needs of customers in other states, rather than the local needs of Kentucky customers.

The issue of siting was addressed by a number of comments in this proceeding. The AG believes that one agency should have jurisdiction over the entire transmission system in Kentucky. As long as the transmission system in place is to serve jurisdictional customers, and as long as the utilities in Kentucky are obligated to serve jurisdictional customers, the AG's position is that the Commission must retain jurisdiction and authority over the transmission system in Kentucky.

LG&E/KU state that authority over transmission line construction should remain with the Commission through the certificate of need process, and that giving the oversight and jurisdiction to an entity other than the Commission would likely cause projects to be unduly delayed by a long legal and regulatory process.

Intervenor Madison believes the federal government should make the decisions on regional transmission sites and deregulation efforts. He further believes that native load customers, merchant plants and electric utilities that engage in off-system sales should pay a proportionate part for transmission upgrades.

Big Rivers and Kenergy assert that the Commission should have a substantial role in the area of transmission and generation siting In addition, they state that any new generation should be developed on existing, underdeveloped generation plant sites, and that the cost of transmission system upgrades necessitated by merchant plants should be borne by the party causing and benefiting from the upgrade.

The Commission finds that siting electric generating and transmission facilities requires a delicate balance to ensure that local interests are adequately protected and to avoid adverse consequences to Kentucky's utilities, their customers, and the public at large. Therefore, we believe that there should be some regulatory body with jurisdiction over the siting of new merchant plants and transmission facilities built by entities that do not operate under our jurisdiction. Since this is a matter to be considered by the Kentucky General Assembly, the Commission reaches no conclusion in this Order on the particulars of a siting statute.

SUMMARY AND CONCLUSIONS

The Commission is obligated to ensure that our jurisdictional utilities plan to have sufficient generating capacity, reserve margins, and transmission capabilities to adequately provide reliable electric service at reasonable costs to Kentucky ratepayers. Meeting this obligation now requires a much higher degree of review due to the myriad of changes in the electric industry over the past decade as discussed earlier in this Order. The Commission is also obligated to ensure that our jurisdictional utilities, particularly those that purchase power from affiliates in other states, are appropriately planning to meet the future demands of Kentucky customers. Two of Kentucky's jurisdictional utilities, AEP-KY and ULH&P, have historically relied upon Ohio affiliates to supply part or all of their power requirements under FERC contracts at cost-based rates. As a result of FERC Order 888 authorizing market-based wholesale power contracts, and electric restructuring in Ohio, those affiliates are now seeking to sell power at market-based prices. Thus, Kentucky ratepayers are clearly at risk of paying higher electric rates as a result of decisions to embrace and encourage competitive electric markets by regulatory agencies outside Kentucky.

As repeatedly seen across the nation in recent years, the move to deregulate generation and depart from traditional, cost-based pricing in parts of the country has resulted in market prices that far exceed cost-based prices. These results, together with changes in FERC policies have transformed, and are continuing to transform, the nation's wholesale power markets. For these reasons, the Commission now, more than ever, considers the issues of appropriate generation planning and transmission planning to be of the utmost importance to the Commonwealth and its citizens. We recognize that such planning is an ongoing process that is dynamic in nature and requires continued review and evaluation. In order that these issues may be properly monitored, we expect our jurisdictional utilities to include sufficient in-depth analyses of their respective generation and transmission plans in their next scheduled IRP filings, which, except for ULH&P, are due in late 2002 or early 2003.

The above direction applies to the six jurisdictional electric utilities' scheduled IRP filings. The IRP filing schedule, as set out in 807 KAR 5:058, requires that each utility file a new IRP on a triennial basis. Given the pace of change within the electric industry in recent years, which is unprecedented in the history of the industry, and given the potential impact of such changes on Kentucky's electric industry, the Commission believes that an annual review of certain planning-related information is needed. While the utilities' triennial IRPs are extremely informative and detailed, current information is needed on a more frequent basis so the Commission can monitor the utilities' most current assessments of their existing supply resources, future demand, reserve margins and the need for additional resources.

The specific information that each of the six major jurisdictional electric utilities will be required to file is set out in Appendix G to this Order. Generally, the information is similar to what the utilities' supplied in response to the Commission's Order that initiated this proceeding. Given that the Midwest and the ECAR regions experience their overall peak demands in the summer, and being mindful that the supply and transmission problems experienced by utilities in the region, including some of Kentucky's utilities, have typically occurred during the summer, we find that such information should be submitted well in advance of the summer peak season. Therefore, until notified otherwise, the utilities will be required to file the information called for in Appendix G, no later than March 1 of 2002, and in succeeding years as well. However, we recognize that resource assessments and resource planning are ongoing, continual processes that are revised and updated frequently. For that reason, we will also require the utilities to make an additional filing, no later than July 1 of each year, to inform the Commission of any changes since their March filing, or to report that there have been no changes thereto.

We conclude that Kentucky's transmission system was designed and built to serve Kentucky's native load. Today, that transmission system is adequate to reliably serve native load and a significant portion of the proposed merchant plants. However, it was not designed to accommodate the volume of wholesale transactions resulting from FERC's policy to create a competitive wholesale power market. As the volume of wholesale power transactions on Kentucky's transmission system increases, the ability of our jurisdictional utilities to continue providing reliable electric service to their respective native load customers could be affected. To ensure that Kentucky's native load electric customers are not adversely affected by these increasing volumes of wholesale transactions, service to native load customers should receive a priority if the transmission system is unable to accommodate all power transactions. The Commission recommends that legislation be enacted to clearly articulate a state policy that in the event that a jurisdictional utility's transmission system is unable to continue providing reliable service to all customers, native load customers can be curtailed only after all other customers have been curtailed.

To handle the transmission volumes envisioned by the FERC, Kentucky's transmission facilities may need to be upgraded. The costs of any needed upgrades should be paid for by those creating the costs. When additional transmission capacity is determined to be necessary, new and emerging technologies should be considered as an alternative to constructing additional lines.

There is no credible evidence that merchant plants will provide economic benefits to Kentucky's electric utility customers sufficient to justify transmission system expansions. Rather, it appears that any economic benefits will flow to out-of-state customers. The Commission is supportive of efforts to promote the benefits of competitive wholesale power markets as long as those benefits are not achieved at the expense of Kentucky's low electric rates. The Commission is acutely aware that the transmission system was not designed to serve multiple merchant plants.

The transmission study indicated that approximately 6,000 to 7,800 MW of the currently proposed 11,300 MW of generation could be exported under peak conditions if constructed as proposed. Because of the TLR and operating procedures, the proposed merchant plants will not adversely affect the delivery of power to native load.

Generation and transmission issues currently being debated at the regional and federal levels could have a profound effect on Kentucky's utility customers. The Commission will continue to monitor these issues and advocate the interests of Kentucky customers.

FINDINGS AND ORDERING PARAGRAPHS

The Commission, based on the evidence of record and being otherwise sufficiently advised, finds that:

1. The Commonwealth of Kentucky benefits from having some of the lowest electric rates in the nation and it is in the best interests of the Commonwealth and its citizens to maintain these low electric rates into the future.

2. Numerous events and decisions that are beyond the control of Kentucky and its decision-makers are affecting Kentucky's ability to continue to ensure that the low electric rates it presently enjoys will continue into the future.

3. This Commission should continue to actively participate in any matters before the FERC and in regional forums, including those involving RTOs, that may impact Kentucky.

4. The resource plans of Kentucky's major jurisdictional electric utilities for meeting the future short-term electric power requirements of their native load customers adequately address the need to provide reliable service at reasonable costs.

5. The resource plans of Big Rivers, East Kentucky, and LG&E/KU adequately address the need to provide reliable service at reasonable costs on a longer-term basis, through 2010. The resource plans of AEP-KY and ULH&P do not adequately address the need to provide reliable service at reasonable costs beyond the terms of their respective wholesale power contracts that expire over the next 3 to 5 years.

6. The current level of reliance on purchased power and gas-fired peaking capacity by Kentucky's major jurisdictional electric utilities is reasonable given the major changes that have impacted, and are continuing to impact, the electric utility industry.

7. DSM is an important component of resource planning and should be thoroughly evaluated by Kentucky's major jurisdictional electric utilities as part of their IRPs prepared pursuant to 807 KAR 5:058.

8. The possible creation of a public power authority to develop coal-fired generation in Kentucky and market the output to Kentucky's electric utilities is an issue that should be considered by the Energy Board.

9. Power produced by merchant power plants should be considered as a resource option by Kentucky's jurisdictional electric utilities and purchases from merchant plants should be analyzed on the basis of cost and other relevant factors.

10. Kentucky's six major jurisdictional electric utilities should conduct a joint investigation of the feasibility of shared ownership of future base load generation and file a joint report, in this docket, which summarizes the investigation and the conclusions reached no later than July 1, 2002.

11. Kentucky's six major jurisdictional electric utilities should conduct a joint investigation of the feasibility of coordinating scheduled maintenance of their generating units and file a joint report, in this docket, which summarizes the investigation and conclusions reached no later than July 1, 2002.

12. Kentucky's major jurisdictional electric utilities should conduct a renewed analysis of appropriate reserve margins to be used for planning purposes and include that analysis in their next IRPs filed pursuant to 807 KAR 5:058.

13. With minor upgrades as noted in CAI's report, Kentucky's transmission system is capable of accommodating between 6,000 MW and 7,800 MW of the more than 11,300 MW of generation currently proposed in Kentucky. Thus, under existing utility operating procedures and the TLR procedures established by the NERC, construction of this level of new generation should not adversely affect the delivery of power to native load customers.

14. Kentucky's existing transmission system was not designed to handle the volume of bulk power transfers that would occur under the wholesale power markets envisioned under FERC's policies on the development of open access transmission and large regional transmission organizations without significant upgrades.

15. We expect that Kentucky will continue its current regulatory structure as a means of maintaining our low rates and that we will remain vigilant in monitoring issues at FERC and in other states that may impact Kentucky. At present, we do not envision events occurring in Kentucky that will have the sort of material, negative impacts on the electricity utility industry here that have occurred elsewhere in the country.

16. Unless it can be demonstrated that transmission upgrades needed to either enhance the development of wholesale power markets or accommodate new non-jurisdictional generation built in Kentucky are necessary to enhance service to Kentucky's native load customers, the costs of such upgrades should not be borne by those customers.

17. There is a clear need for a regulatory body in Kentucky with jurisdiction over the siting of merchant power plants and the siting of transmission facilities constructed by entities that do not fall under the jurisdiction of this Commission.

18. Legislation should be enacted in the Commonwealth to articulate a policy to ensure that if a jurisdictional utility's transmission system cannot reliably continue to provide service to all customers, service to native load customers can be curtailed only after service to all other customers has been curtailed.

19. Electric restructuring, open access transmission, development of regional transmission organizations, construction of merchant power plants, and other issues are contributing to rapid, unprecedented change in the electric industry. In order that the Commission may stay apprised of the impact that such changes are having on the resource planning of Kentucky's six major jurisdictional electric utilities, those utilities should annually file certain planning-related information with the Commission as set forth in Appendix G to this Order. The utilities' initial informational filings should be filed with the Commission no later than March 1, 2002.

IT IS THEREFORE ORDERED that:

1. Kentucky's six major jurisdictional electric utilities shall conduct a joint investigation of the feasibility of shared ownership of future base load generation and shall file, no later than July 1, 2002, a joint report, in this docket, which summarizes the investigation and the conclusions reached.

2. Kentucky's six major jurisdictional electric utilities shall conduct a joint investigation of the feasibility of coordinating scheduled maintenance of their generating

units and shall file, no later than July 1, 2002, a joint report, in this docket, which summarizes the investigation and conclusions reached.

3. Kentucky's major jurisdictional electric utilities shall conduct a renewed analysis of appropriate reserve margins to be used for planning purposes and shall include that analysis in their next IRPs filed pursuant to 807 KAR 5:058.

4. Kentucky's major jurisdictional electric shall thoroughly evaluate DSM as a component of the IRPs filed pursuant to 807 KAR 5:058.

5. Kentucky's six major jurisdictional electric utilities shall file, no later than March 1, 2002, and annually thereafter the information listed in Appendix G to this Order. The utilities shall supplement these filings no later than July 1, 2002 and annually thereafter as described in this Order.

Done at Frankfort, Kentucky, this 20th day of December, 2001.

By the Commission

ATTEST:

Thomas M. Dorman

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION
IN ADMINISTRATIVE CASE NO. 387 DATED DECEMBER 20, 2001

1. Witnesses at the August 13, 2001 Public Hearing:
   Ron Crouch, Kentucky State Data Center,
   University of Louisville

   J. R. Wilhite, Commissioner,
   Department of Community Development, Economic Development Cabinet

   William G. Brundage, Ph.D., Commissioner,
   Office for the New Economy, Economic Development Cabinet

   Stephen N. Dooley, Deputy Chief Information Officer,
   Governor's Office for Technology

2. Witnesses at the September 19, 2001 Public Hearing:

   Big Rivers Electric Corporation:
   - David Spainhoward
   - William Blackburn
   - Travis Housley

   East Kentucky Power Cooperative Inc.:
   - Ron Brown
   - Paul Atchison

   Kentucky Power Company d/b/a AEP:
   - Errol Wagner
   - Myron Adams
   - Paul Johnson

   Louisville Gas & Electric Company / Kentucky Utilities Company:
   - Lonnie Bellar
   - Daniel Becher
   - Bruce Sauer
   - Ronald Willhite

The Union Light, Heat & Power Company:
Richard Stevie
Ronald Jackups
Douglas Esamann (submitted testimony but did not testify)

3. Witnesses at the October 1, 2001 Public Hearing:

Attorney General's Office of Rate Intervention:
David Brown Kinloch

Natural Resources & Environmental Protection Cabinet, Division of Energy:
Geoffrey M. Young

Gallatin Steel:
Dr. Dennis W. Goins

Municipal Electric Power Assoc. of Kentucky:
Warner J. Caines

Owensboro Municipal Utilities:
Robert M. Carper
Robert E Hunzinger

Thoroughbred Generating Co.:
Jacob Williams

Robert Madison (Residential Customer of LG&E)

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISION
IN ADMINISTRATIVE CASE NO. 387 DATED DECEMBER 20, 2001

Big Rivers Electric Corp.

Plant Name	Unit #	Location	Operation Date	Facility Type	Demo Perf. MW	Name Plate MW	Fuel	Plant MW
Reid	1	Sebree	1966	Steam	65	80	Coal	65
Coleman	1	Hancock Co.	1969	Steam	150	160	Coal	455
	2		1970	Steam	150	160	Coal	
	3		1972	Steam	155	160	Coal	
Station Two	1	Sebree	1973	Steam	154	176	Coal	315
	2		1974	Steam	161	179	Coal	
Green	1	Sebree	1979	Steam	231	242	Coal	454
	2		1981	Steam	223	242	Coal	
Wilson	1	Ohio Co.	1986	Steam	409	440	Coal	409
Reid CT	1	Sebree	1976	CT	65	66	NG/Oil	65
Total Big Rivers*								1763

* Big Rivers' capacity is leased to a non-regulated operator.
It purchases 100% of its current capacity requirements.

East Kentucky Power Cooperative , Inc.

Plant Name	Unit #	Location	Operation Date	Facility Type	Demo. Perf. MW	Name Plate MW	Fuel	Plant MW
Dale	1	Ford	1954	Steam	24	24	Coal	198
	2		1954	Steam	24	24	Coal	
	3		1957	Steam	75	80	Coal	
	4		1960	Steam	75	80	Coal	
Cooper	1	Somerset	1965	Steam	116	100	Coal	341
	2		1969	Steam	225	221	Coal	
Spurlock	1	Maysville	1977	Steam	325	340	Coal	850
	2		1981	Steam	525	586	Coal	
Smith	1	Trapp	1996	CT	149	110	NG/Oil	546
	2		1996	CT	149	110	NG/Oil	
	3		1996	CT	149	110	NG/Oil	
	4		2001	CT	108	108	NG/Oil	
	5		2001	CT	108	108	NG/Oil	
Total East Ky.								1935

American Electric Power

			Operation	Facility	Demo Perf.	Name Plate		Plant
Plant Name	Unit #	Location	Date	Type	MW	MW	Fuel	MW
Big Sandy	1	Louisa	1963	Steam	260	280	Coal	1060
	2		1969	Steam	800	816	Coal	
Total AEP								1060

Kentucky Utilities

			Operation	Facility	Demo Perf.	Name Plate		Plant
Plant Name	Unit #	Location	Date	Type	MW	MW	Fuel	MW
E.W.Brown	1	Burgin	1957	Steam	106	100	Coal	1726
	2		1963	Steam	170	156	Coal	
	3		1971	Steam	441	409	Coal	
	5		2001	CT	164	164	NG/Oil	
	6		2001	CT	164	164	NG/Oil	
	7		2001	CT	164	164	NG/Oil	
	8		1995	CT	135	119	NG/Oil	
	9		1994	CT	125	119	NG/Oil	
	10		1995	CT	135	119	NG/Oil	
	11		1996	CT	122	119	NG/Oil	
Ghent	1	Ghent	1974	Steam	502	511	Coal	2022
	2		1977	Steam	507	511	Coal	
	3		1981	Steam	513	511	Coal	
	4		1984	Steam	500	511	Coal	
Green River	1	Central City	1950	Steam	29	30	Coal	239
	2		1950	Steam	30	30	Coal	
	3		1954	Steam	73	60	Coal	
	4		1959	Steam	107	100	Coal	
Pineville	1	Four Miles	1951	Steam	34	30	Coal	34
Tyrone	1	Tyrone	1947	Steam	30	25	Oil	136
	2		1948	Steam	33	25	Oil	
	3		1953	Steam	73	60	Coal	
Dix Dam	1	Burgin	1925	Hydro	8	8		24
	2		1925	Hydro	8	8		
	3		1925	Hydro	8	8		
Haefling	1	Lexington	1970	CT	15	21		44
	2		1970	CT	14	21		
	3		1970	CT	15	21		
Lock 7	1	Ky. River		Hydro	2	2		2
Total KU								4,227

Louisville Gas & Electric Co.

Plant Name			Operation	Facility	Demo Perf.	Name Plate		Plant
	Unit #	Location	Date	Type	MW	MW	Fuel	MW
Trimble	1	Bedford	1990	Steam	*495	566	Coal	495
Mill Creek	1	Louisville	1972	Steam	303	356	Coal	1456
	2		1974	Steam	301	356	Coal	
	3		1978	Steam	386	463	Coal	
	4		1982	Steam	466	544	Coal	
Cane Run	4	Louisville	1962	Steam	155	164	Coal	563
	5		1966	Steam	168	209	Coal	
	6		1969	Steam	240	272	Coal	
Cane Run	11	Louisville	1968	CT	16	16	NG/Oil	16
Paddys Run	11	Louisville	1968	CT	17	16	NG/Oil	43
	12		1968	CT	26	33	NG/Oil	
Zorn	1	Louisville	1969	CT	16	18	NG/Oil	16
Waterside	7	Louisville	1964	CT	17	20	NG/Oil	33
	8		1964	CT	16	25	NG/Oil	
Falls of Ohio		Louisville	1928	Hydro	48	80		48
Total LG&E								2,670
*LG&E is entitled to 75% of plant output.								-124
								2,546

Total Regulated Generating Capacity
(Big Rivers' leased capacity not included) 9,892

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION
IN ADMINISTRATIVE CASE NO. 387 DATED DECEMBER 20, 2001

1992 RESOURCES AND REQUIREMENTS PER 1991 IRP FILINGS

	Big Rivers	East Ky.	AEP-KY	KU	LG&E	ULH&P	Coincident Peak Total
SUMMER							
Requirements (MW)							
Peak Demand	1,490	1,294	1,047	2,973	1,988	615	9,256
Resources (MW)							
Capacity Resources	1,720	1,478	1,060	3,097	2,562	0	9,917
Capacity Purchases	178	65	390	393	0	744	1,770
Total Resources	1,898	1,543	1,450	3,490	2,562	744	11,687
Excess/(Deficit)	408	249	403	517	574	129	2,431
Reserve Margin (%)	27.4	19.2	38.5	17.4	28.9	21.0	26.3
WINTER							
Requirements (MW)							
Peak Demand	1,380	1,348	1,169	2,788	1,475	534	8,561
Resources (MW)							
Capacity Resources	1,720	1,478	1,060	3,162	2,444	0	9,864
Capacity Purchases	178	180	390	254	0	710	1,712
Total Resources	1,898	1,658	1,450	3,416	2,444	710	11,576
Excess/(Deficit)	518	310	281	628	969	176	3,015
Reserve Margin (%)	37.5	23.0	24.0	22.5	65.7	33.0	35.2

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUKCY PUBLIC SERVICE COMMISSION
IN ADMINISTRATIVE CASE NO. 387 DATED DECEMBER 20, 2001

Projected Year 2002	Big Rivers	East Ky	AEP-KY	LG&E/KU	ULH&P	NCP Total*
Requirements:						
Forecasted Peak Demand (MW)	632	2,323	1,538	6,705	842	12,040
Resources:						
Installed Capacity (MW) (Net Cap)	0	2,053	1,060	6,900	0	10,013
Firm Purchases (MW)	775	620	390	567	842	3,194
New DSM Resources (MW)	0	0	0	65	0	65
Total Resources (MW)	775	2,673	1,450	7,532	842	13,272
Excess (Deficit) (MW)	143	350	-88	840	0	N/A
Actual Reserve Margin	22.5%	15.1%	-5.7%	12.5%	0.0%	N/A
Planning Reserve Margin	0.0%	15.0%	12.0%	11-14%	0.0%	N/A

Projected Year 2006	Big Rivers	East Ky	AEP-KY	LG&E/KU	ULH&P	NCP Total*
Requirements:						
Forecasted Peak Demand (MW)	677	2,622	1,670	7,318	922	13,209
Resources:						
Installed Capacity (MW) (Net Cap)	0	2,053	1,060	6,900	0	10,013
New Capacity Additions (MW)	0	820	0	780	0	1,600
Firm Purchases (MW)	775	170	0	540	922	2,407
New DSM Resources (MW)	0	0	0	150	0	150
Total Resources (MW)	775	3,043	1,060	8,370	922	14,170
Excess (Deficit) (MW)	98	419	-610	1,052	0	N/A
Actual Reserve Margin	14.5%	16.0%	-36.5%	14.3%	0.0%	N/A
Planning Reserve Margin	0.0%	15.0%	12.0%	11-14%	0.0%	N/A

Projected Year 2010	Big Rivers	East Ky	AEP-KY	LG&E/KU	ULH&P	NCP Total*
Requirements:						
Forecasted Peak Demand (MW)	725	2,973	1,752	7,883	970	14,303
Resources:						
Installed Capacity (MW) (Net Cap)	0	2,053	1,060	6,900	0	10,013
New Capacity Additions (MW)	0	820	0	1,420	0	2,240
Firm Purchases (MW)	775	550	0	500	0	1,825
New DSM Resources (MW)	0	0	0	150	0	150
Total Resources (MW)	775	3,423	1,060	8,970	0	14,228
Excess (Deficit) (MW)	50	450	-692	1,087	-970	N/A
Actual Reserve Margin	6.9%	15.1%	-39.5%	13.8%	N/A	N/A
Planning Reserve Margin	0.0%	15.0%	12.0%	11-14%	0.0%	N/A

* NCP - Non-coincident peak demand = the sum of the utilities peak Demands. It is non-c Oincident Because different utilities' peaks occur at different times of the year.

APPENDIX E

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION
IN ADMINISTRATIVE CASE NO. 387 DATED DECEMBER 20, 2001

Calendar Year 2000	Big Rivers	East Ky.	AEP-KY	LG&E / KU	ULH&P	Total (NCP)
Peak Demand*	676	2,109	1,558	6,264	863	11,470
Utility Generation**	0	9,162,900	9,810,700	33,604,800	0	52,578,400
Purchase Power **	4,205,800	2,447,400	2,935,500	11,033,600	4,012,500	24,634,800
Native Load Sales**	3,540,900	10,079,000	6,967,300	27,977,800	3,843,700	52,408,700
Off-System Sales**	598,500	773,200	5,391,500	14,407,400	0	21,170,600

* Stated in megawatts, equal to 1,000 kilowatts

** Stated in megawatt-hours, equal to 1,000 kilowatt-hours

APPENDIX F

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN ADMINISTRATIVE CASE NO. 387 DATED DECEMBER 20, 2001

County	Name	Principal Party	MW	Fuel Type
Ballard	PG&E - La Center (Merchant)	PG&E Disbursed Generating Company, LLC PG&E National Energy Group 111 Washington Ave. Suite 703 Albany, NY 12210	105	Natural Gas Peaking
Breckinridge	DP&L Hardinsburg (Merchant)	DP&L P.O. Box 1247 Courthouse Plaza, SW Dayton OH 45401	400	Fuel Oil Peaking
Campbell	Trigen Cinergy-Silver Grove (Non-Jurisdictional)	Trigen Energy Corp and Cinergy One Water Street White Plains, NY 10601	20	Natural Gas Peaking
Clark	KY Pioneer Energy (Merchant)	Global Energy, Inc. 312 Walnut Street, Suite 2000 Cincinnati, OH 45202	540	Coal Gasification Baseload
Clark	East Kentucky Power JK Smith Plant (Jurisdictional)	East Kentucky Power Cooperative, Inc. 4775 Lexington Road P.O.Box 707 Winchester, KY 40392	312	Natural Gas Peaking
Estill	Calla Energy (Merchant)	Calla Energy Partners 898 Coal Wash Road Irvine, KY 40336	110	Waste Coal Baseload
Henderson	Cash Creek (Merchant)	Cash Creek Generation, LLC 3600 National City Tower 101 South Fifth Street Louisville, KY 40202	1,000	Bituminous Coal Baseload
Henderson	Columbia-Crane Creek (Merchant)	Orion Power Holdings 10th Floor, 7 East Redwood Street Baltimore, MD 21252	500	Natural Gas Peaking
Jefferson	LG&E Paddy's Run (Jurisdictional)	Louisville Gas & Electric 12500 Fair Lakes Circle, Suite 350 Fairfax, VA 22033-3804	151	Natural Gas Peaking
Kenton	Cinergy-Erlanger (Non-Jurisdictional)	CinCap IX Cinergy 2804 Atrium II 139 East Fourth Street Cincinnati, OH 45202	96	Natural Gas Peaking
Knott	Kentucky Mountain Power (Merchant)	EnviroPower, LLC 2810 Lexington Financial Center 250 West Main Street Lexington, KY 40507	500	Waste Coal Baseload
Lawrence	Riverside Generating (Merchant)	Dynegy 1000 Louisiana Street Suite 5800 Houston, TX 77002	1,040	Natural Gas Peaking

Marshall	Calvert City Power (Merchant)	Enron Corporation 1400 Smith Street Houston, TX 77002	540	Natural Gas Peaking
Marshall	Kentucky Western Power (Merchant)	EnviroPower, LLC 2810 Lexington Financial Center 250 West Main Street Lexington, KY 40507	500	Bituminous Coal Baseload
Marshall	Marshall County Generation (Merchant)	Duke Energy 5400 Westheimer Court Houston, TX 77056-5310	640	Natural Gas Peaking
Marshall	West Lake Energy (Co-Generation)	Westlake Group 2801 Post Oak Blvd. Houston, TX 77056	520	Natural Gas
Marshall	Air Products and Chemicals (Co-Generation)	Air Products and Chemicals 7201 Hamilton Blvd. Allentown, PA 18195	26	Natural Gas
Martin	Kentucky Eastern Power (Merchant)	EnviroPower, LLC 2810 Lexington Financial Center 250 West Main Street Lexington, KY 40507	500	Waste Coal Baseload
Mason	East Kentucky Power Spurlock (Jurisdictional)	East Kentucky Power Cooperative, Inc. 4775 Lexington Road P.O.Box 707 Winchester, KY 40392	270	Bituminous Coal Baseload
Metcalfe	Metcalfe County Generation (Merchant)	Duke Energy 5400 Westheimer Court Houston, TX 77056-5310	640	Natural Gas Peaking
Metcalfe	Summer Shade (Merchant)	PG&E Disbursed Generating Company, LLC PG&E National Energy Group 111 Washington Ave. Suite 703 Albany, NY 12210	105	Natural Gas
Muhlenberg	Throughbred Generating (Merchant)	Peabody Energy 701 Market Street St. Louis, MO 63101-1826	1,500	Bituminous Coal Baseload
Oldham	Bluegrass Generating (Merchant)	Dynegy 1000 Louisiana Street Suite 5800 Houston, TX 77002	624	Natural Gas Peaking
Trimble	LG&E Trimble County (Non-Jurisdictional)	Louisville Gas & Electric 12500 Fair Lakes Circle, Suite 350 Fairfax, VA 22033-3804	1,020	Natural Gas Peaking
		Total Proposed Generation	**11,659**	

* Information obtained from various sources.
Proposed plants as of May 16, 2001 when the Energy Board was established.

APPENDIX G

APPENDIX TO AN ORDER OF THE KETUCKY PUBLIC SERVICE COMMISSION
IN ADMINISTRATIVE CASE NO. 387 DATED DECEMBER 20, 2001

Information to be included in annual resource assessment filings of the utilities

1. Actual and weather-normalized energy sales for the just completed calendar year. Sales should be disaggregated into native load sales and off-system sales. Off-system sales should be further disaggregated into full requirements sales, firm capacity sales, and non-firm or economy energy sales. Off-system sales should be further disaggregated to identify separately all sales where the utility acts as a reseller, or transporter, in a power transaction between two or more other parties.

2. A summary of monthly power purchases for the just completed calendar year. Purchases should be disaggregated into firm capacity purchases required to serve native load, economy energy purchases, and purchases where the utility acts as a reseller, or transporter, in a power transaction between two or more other parties.

3. Actual and weather-normalized monthly coincident peak demands for the just completed calendar year. Demands should be disaggregated into (a) native load demand (firm and non-firm) and (b) off-system demand (firm and non-firm).

4. Load shape curves that show actual peak demands and weather-normalized peak demands (native load demand and total demand) on a monthly basis for the just completed calendar year.

5. Load shape curves showing the number of hours that native load demand exceeded these levels during the just completed calendar year: (1) 70% of the sum of installed generating capacity plus firm capacity purchases; (2) 80% of the sum of installed generating capacity plus firm capacity purchases; (3) 90% of the sum of installed generating capacity plus firm capacity purchases.

6. Based on the most recent demand forecast, the base case demand and energy forecasts and high case demand and energy forecasts for the current year and the following four years. The information should be disaggregated into (a) native load (firm and non-firm demand) and (b) off-system load (both firm and non-firm demand).

7. The target reserve margin currently used for planning purposes, stated as a percentage of demand. If changed from what was in use in 2001, include a detailed explanation for the change.

8. Projected reserve margins stated in megawatts and as a percentage of demand for the current year and the following 4 years. Identify projected deficits and current plans for addressing these. For each year identify the level of firm capacity purchases projected to meet native load demand.

9. By date and hour, identify all incidents during the just completed calendar year when reserve margin was less than the East Central Area Reliability Council's ("ECAR") 1.5% spinning reserve requirement. Include 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. Also identify system conditions at the time.

10. A list identifying and describing all forced outages in excess of 2 hours in duration during the just completed calendar year.

11. A list that identifies scheduled outages or retirements of generating capacity during the current year and the following four years.

12. Identify all planned base load or peaking capacity additions to meet native load requirements over the next 10 years. Show the expected in-service date, size and site for all

planned additions. Include additions planned by the utility, as well as those by affiliates, if constructed in Kentucky or intended to meet load in Kentucky.

13. The following transmission energy data for the just completed calendar year and the forecast for the current year and the following four years:

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

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

c. Peak load capacity of the transmission system.

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

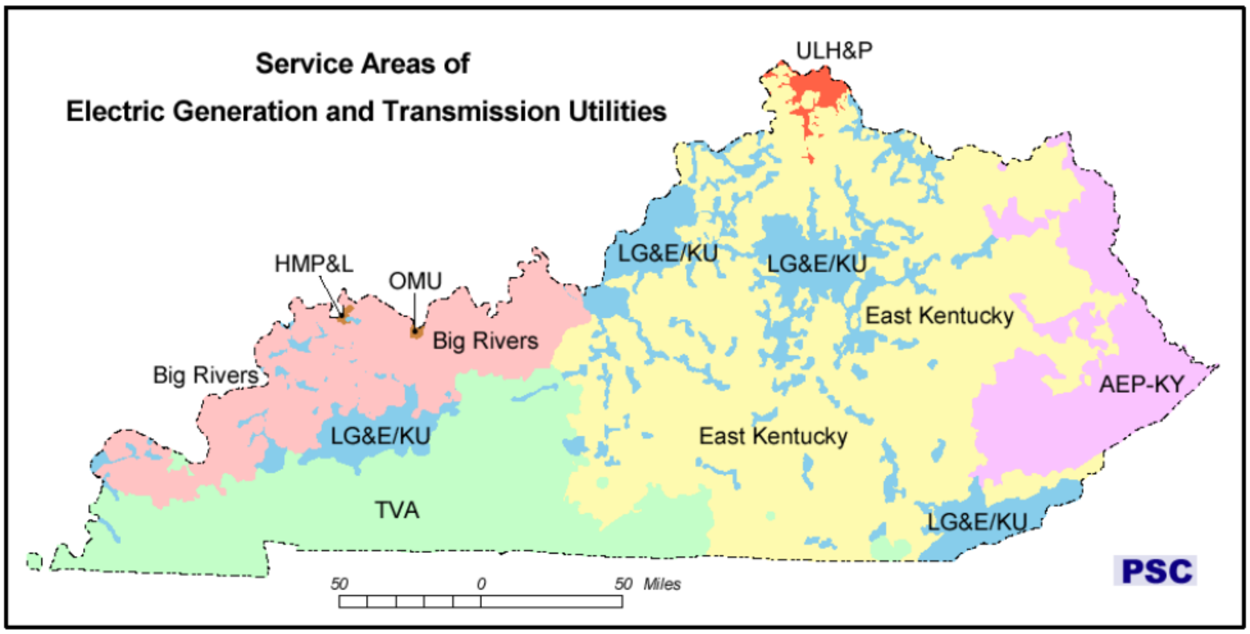
14. Identify all planned transmission capacity additions for the next 10 years. Include the expected in-service date, size and site for all planned additions and identify the transmission need each addition is intended to address.

APPENDIX H

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN ADMINISTRATIVE CASE NO. 387 DATED DECEMBER 20, 2001

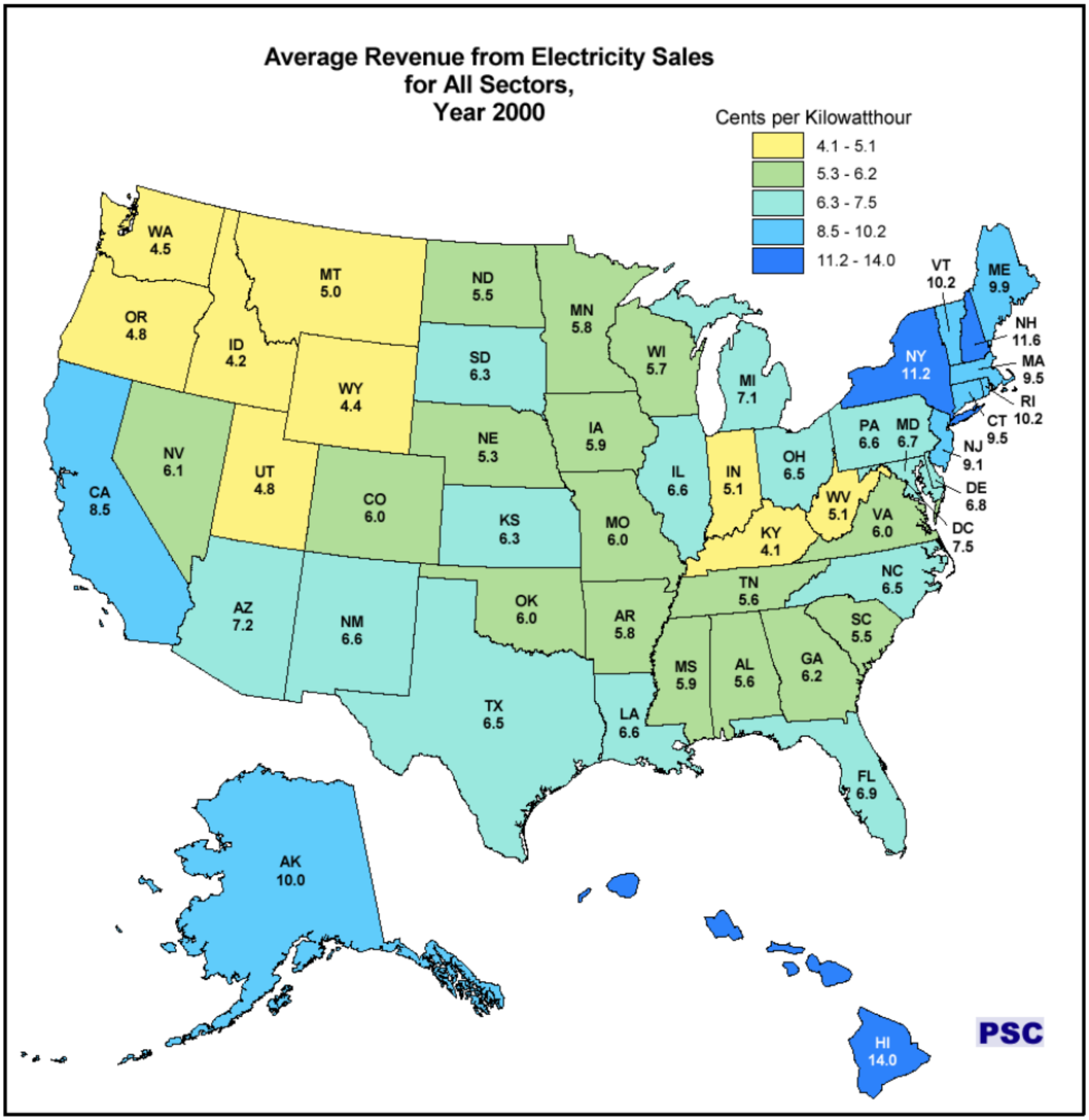
Map 1: Electric Generation and Transmission Utilities

Of the six major jurisdictional electric utilities, four are investor-owned (AEP-KY, LG&E, KU, and ULH&P) and two are not for profit cooperatives (Big Rivers and East Kentucky). TVA and the two municipal power producers (OMU and HMP&L) are non-jurisdictional.



Boundaries are derived from certified territory maps on file with the Public Service Commission. On this map non-jurisdictional municipal distribution utilities have been assigned to their electric supplier.

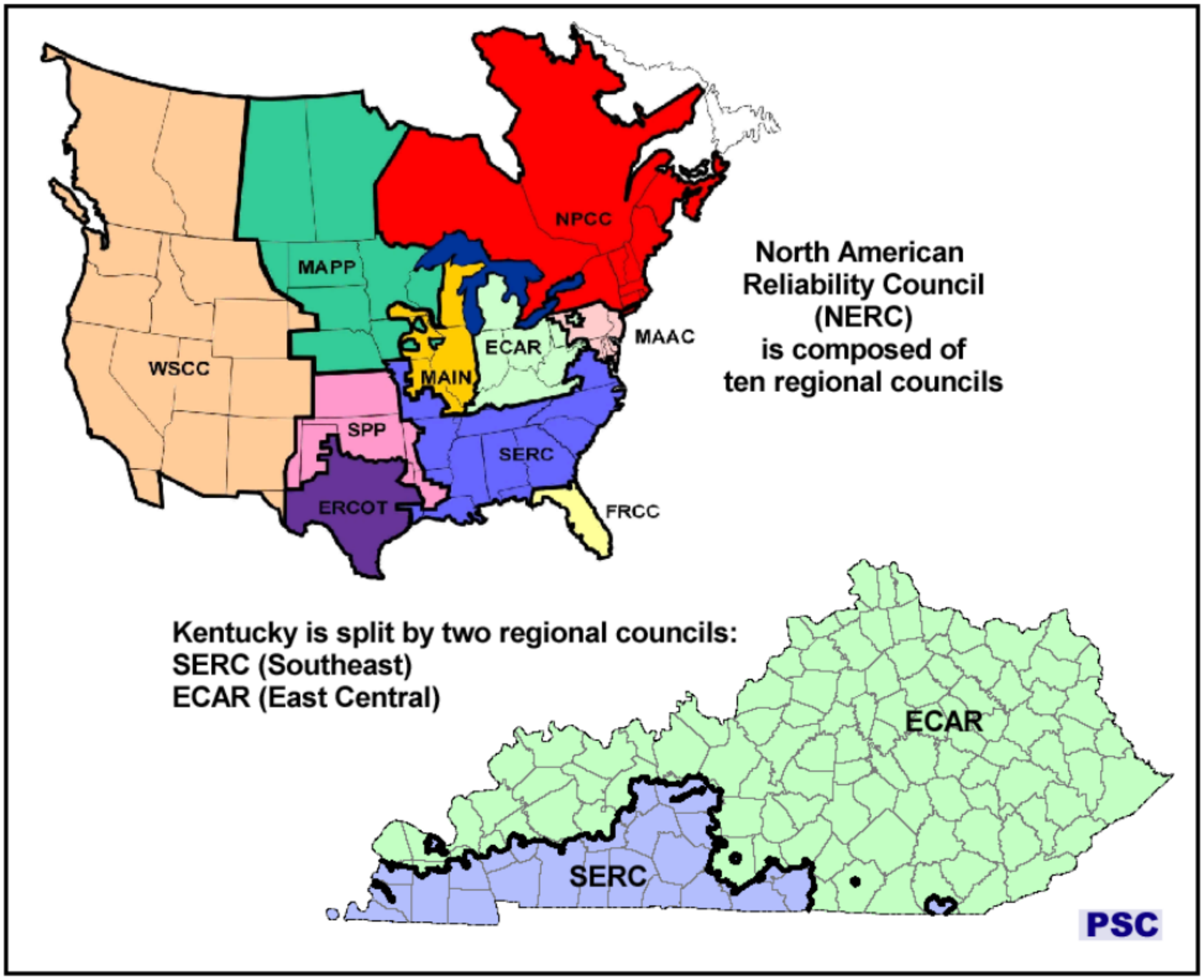
Map 2: Kentucky has some of the lowest electricity rates in the nation



Source: Energy Information Administration, U.S. Dept. of Energy, Table A21: "Sales of Electricity, Revenue, and Average Revenue per Kilowatt-hour (and RSEs) by U.S. Electric Utilities to Ultimate Consumers by Census Division, and State, 2000 and 1999--All Sectors."

Map 3: NERC, ECAR, and SERC Boundaries

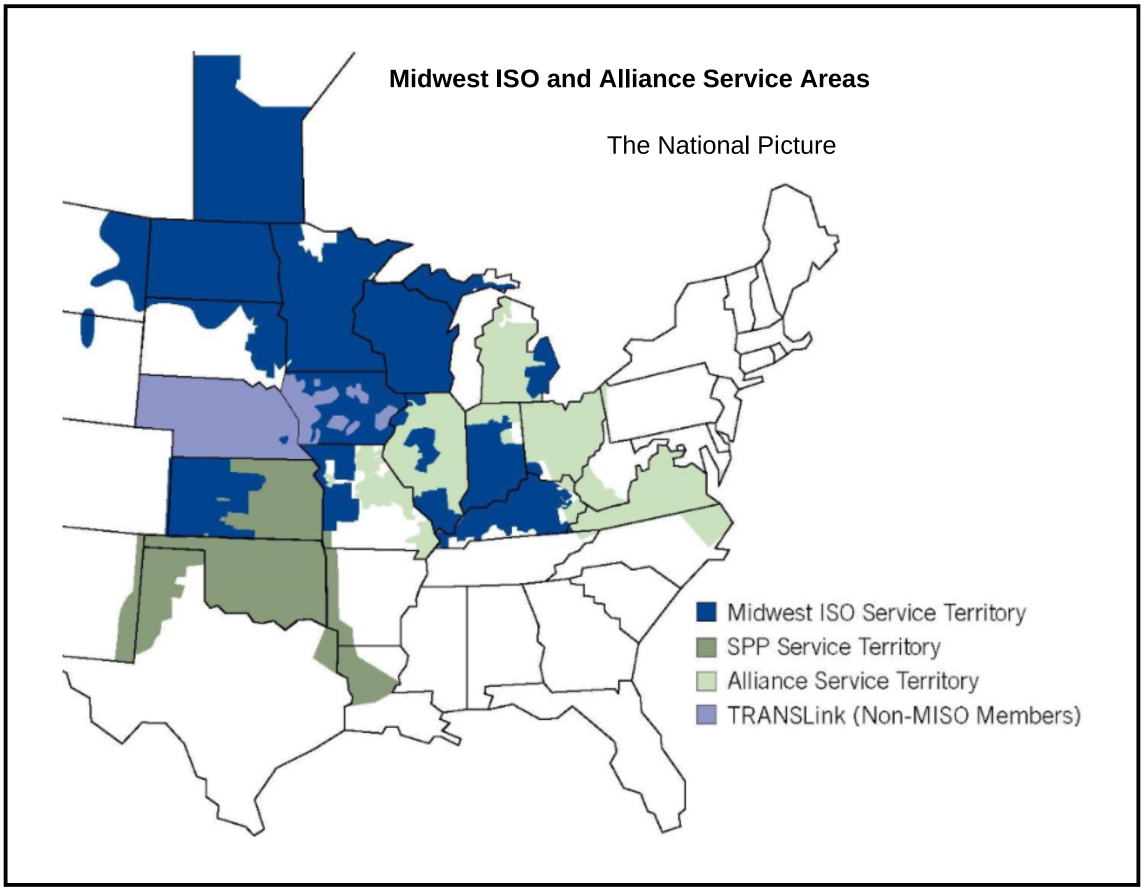
Founded in 1968, the North American Reliability Council (NERC) has operated as a voluntary organization, composed of ten regional councils, in order to promote electric system reliability and security.



Source: NERC web page, www.nerc.com, for the national map; the Kentucky map is derived from boundaries of the electric service areas on file with the Commission

Map 4: Regional Transmission Organizations of the Midwest

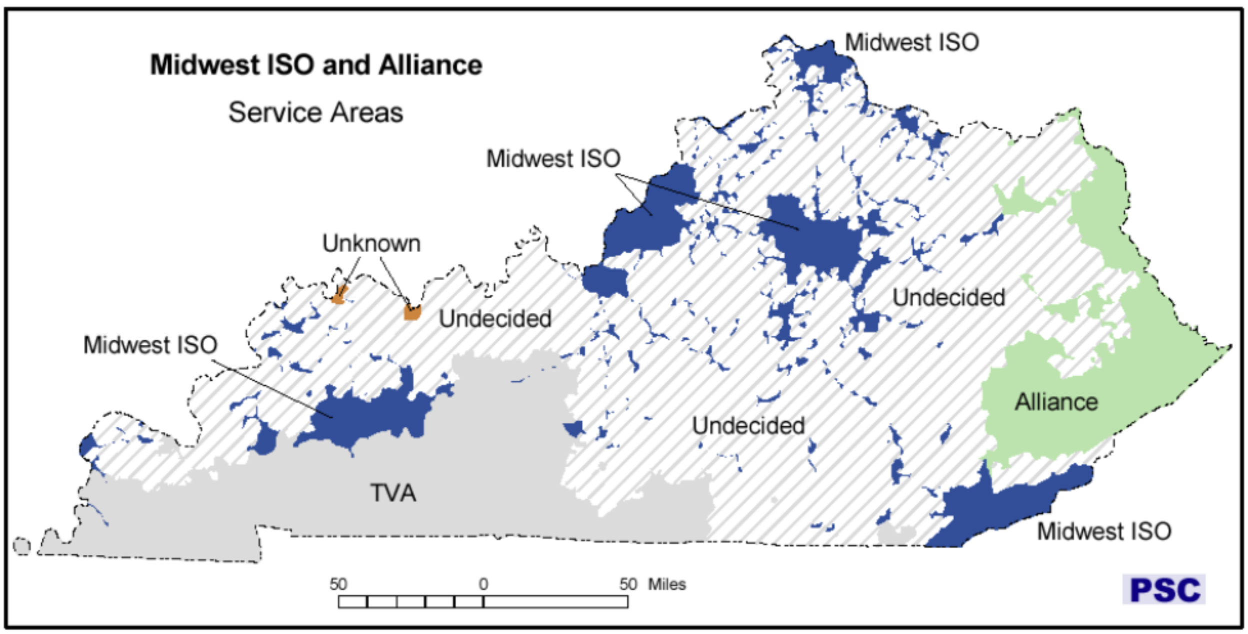
The Midwest ISO and Alliance are regional transmission organizations that have made an inter-RTO agreement with each other. The Midwest ISO has also made agreements with adjacent utility organizations including the Southwest Power Pool (SPP), which is one of NERC's regional councils, and TRANSlink, a proposed independent transmission company composed of members not subject to FERC jurisdiction. For more detailed information on Kentucky's participation in RTOs, refer to the next map.



Source: Midwest ISO

Map 5: Service Areas of Regional Transmission Organizations

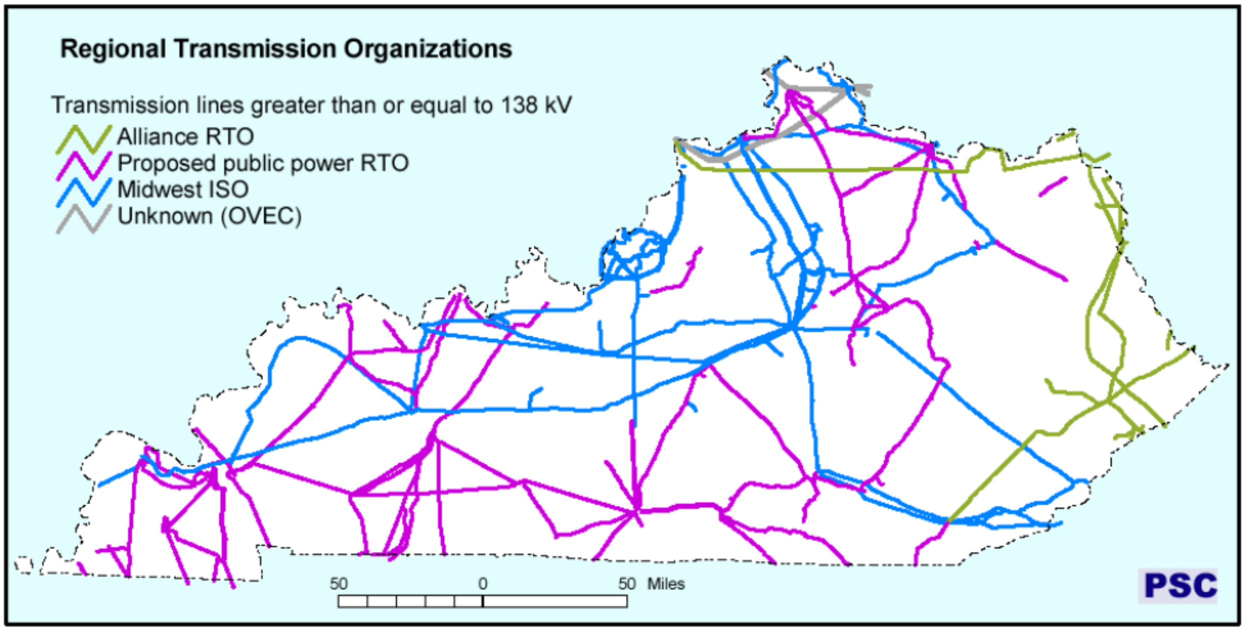
LG&E/KU and ULH&P are members of the Midwest ISO and AEP-KY is a member of the Alliance RTO. (Actually CG&E, ULH&P's parent company, is a member of the Midwest ISO.) Big Rivers and East Kentucky, not for profit cooperatives, are undecided. The membership of the two municipal power producers (OMU and HMP&L) is unknown. TVA, Big Rivers, East Kentucky, and the municipal power producers are not subject to FERC jurisdiction and have not yet chosen to join an RTO. Currently East Kentucky and Big Rivers are in discussion with TVA to form a public power RTO.



Source: Boundaries of member utilities are derived from certified territory maps.

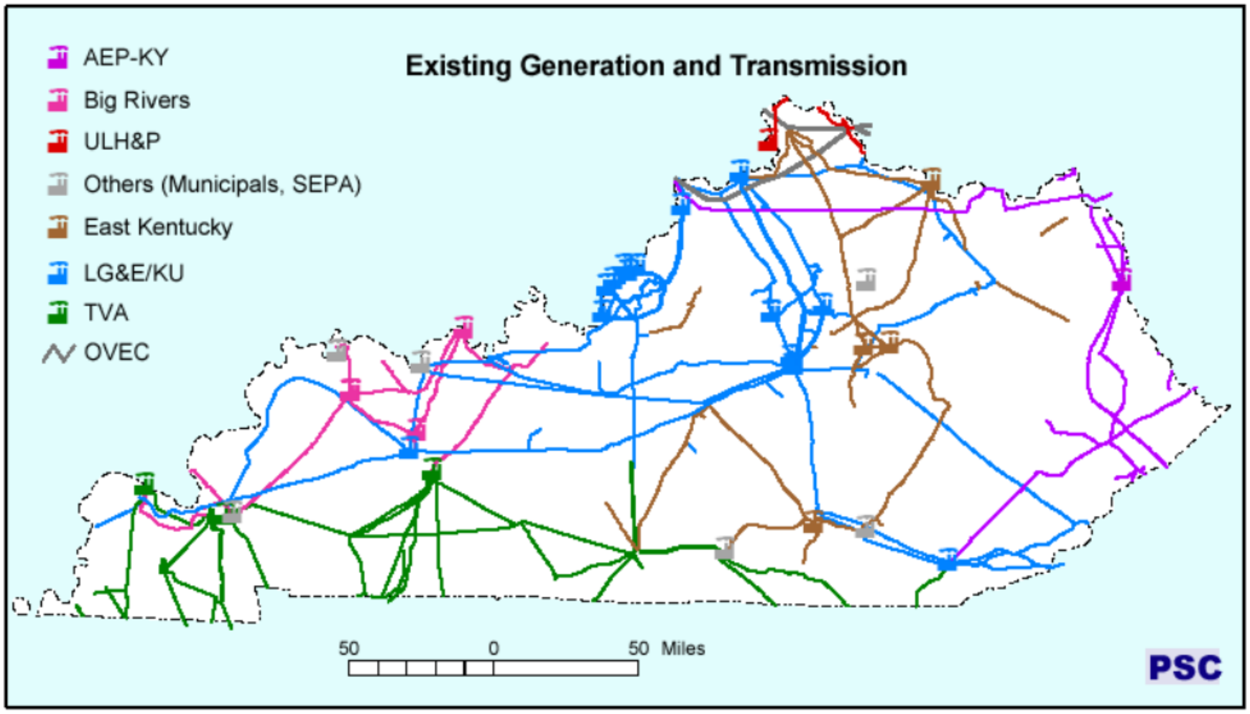
Map 6: RTOs as a Network of Transmission Lines

Another way to look at Regional Transmission Organizations (RTOs) is as a network of transmission lines.



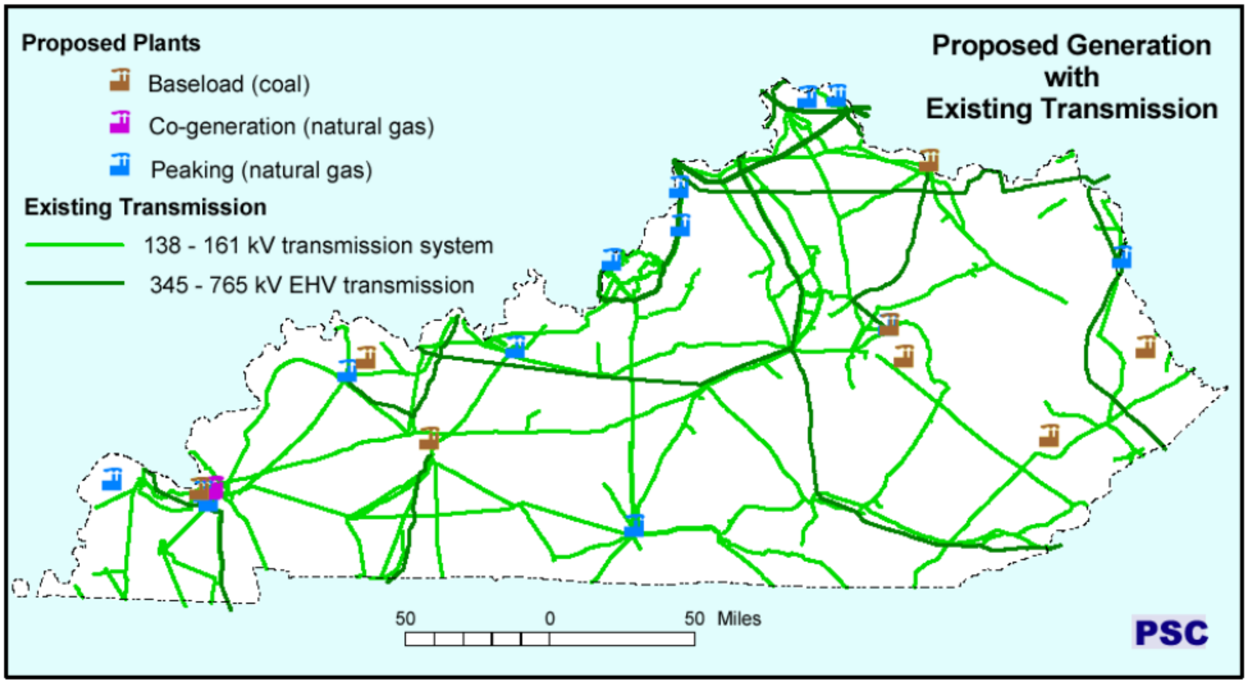
Map 7: Power Plants and Transmission Lines

The transmission system was built by utilities to deliver power from their generating stations to their customers. This is reflected in the ownership and location of the power plants and the transmission lines over 138 kV. Some of the power plants are located close to each other so their symbols overlap.



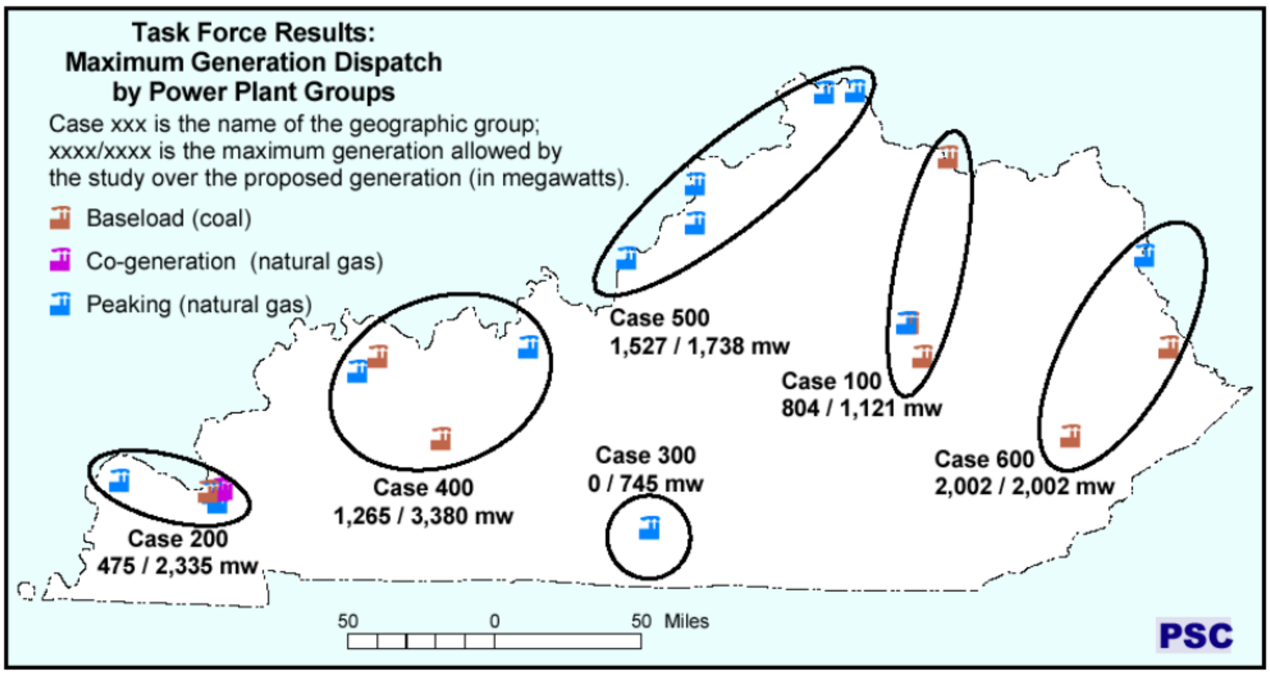
Map 8: Proposed Power Plants with Existing Transmission Lines

This shows the location of the proposed power plants that were included in the transmission study. Some of those power plants are located close to each other and the symbols overlap. Existing transmission lines are shown.



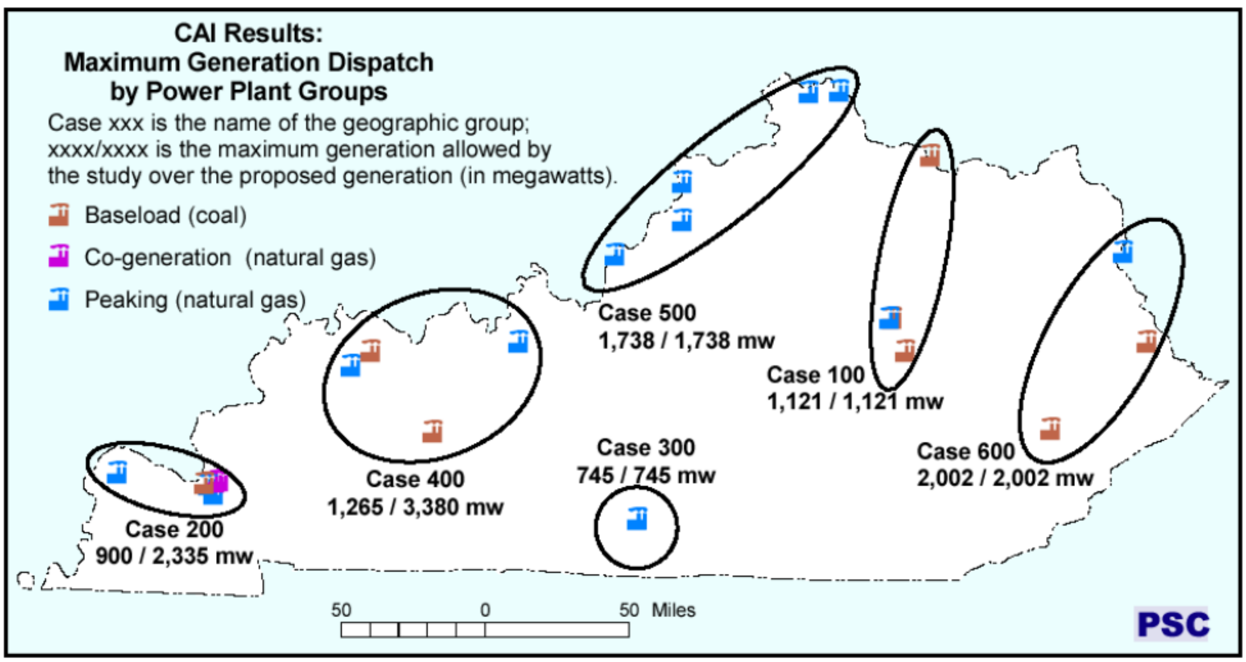
Map 9: Task Force Results of Maximum Generation Supported by the Existing Transmission System

These are the results of the task force electric flow analysis model. The model assumed Summer 2005 Peak conditions and that proposed generation would be exported south, which reflects historical flows under system peak conditions. The results of this model are expressed in terms of the maximum new generation values that can be exported with the existing transmission system in each geographic region (case) compared to the generation that is proposed to be built.



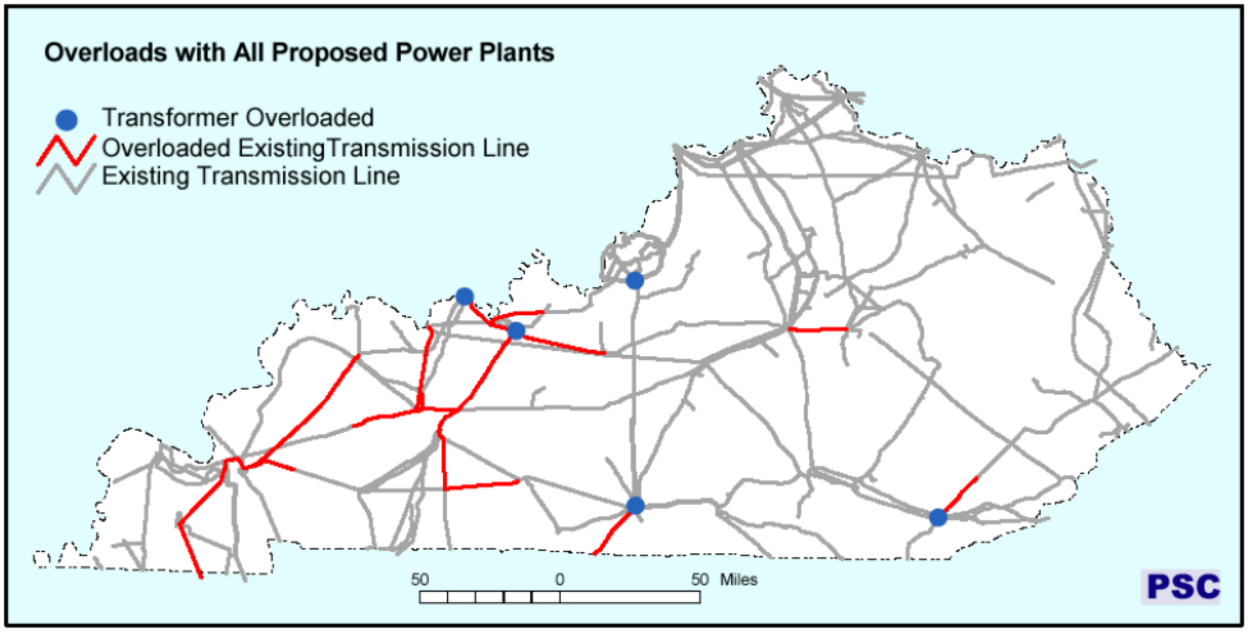
Map 10: CAI Results of Maximum Generation Supported by the Existing Transmission System

These are the results of the CAI electric flow analysis model, which reflects transmission improvements that are not included in the task force model. The model assumed Summer 2005 Peak conditions and that proposed generation would be exported south, which reflects historical flows under system peak conditions. The results of this model are expressed in terms of the maximum new generation values that can be exported with the existing transmission system in each geographic region (case) compared to the generation that is proposed to be built.



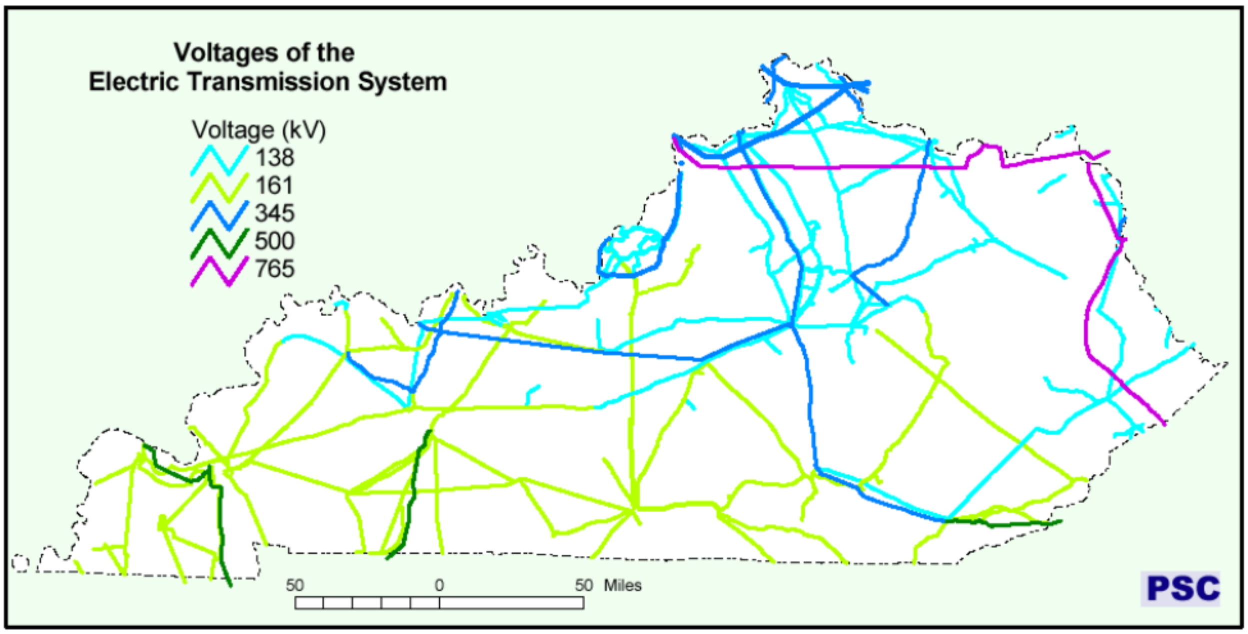
Map 11: Transmission System Overloads

Overloaded transmission facilities, 138 kV and above are identified by the transmission study. These are the effects on the existing transmission system with the transfer of the extra power generated from the proposed power plants to the south.



Map 12: Kentucky's Standard Transmission Voltages Vary from North to South

The extra high voltage (EHV) transmission grid in Kentucky is not well integrated. TVA to the south uses 500 kV transmission, LG&E/KU, Big Rivers, and East Kentucky use 345 kV, and AEP-KY has a 765 kV grid. The EHV grid services a 161 kV and 138 kV transmission system, with the 161 kV located in the southern part of Kentucky and the 138 kV in the north. Different voltages must be interconnected with substations and transformers, which are expensive to build and serve as a bottleneck to the flow of power between systems.



APPENDIX I

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN ADMINISTRATIVE CASE NO. 387 DATED DECEMBER 20, 2001

GLOSSARY OF TERMS AND ACRONYMS

AEP-East	A power pool – part of American Electric Power, that presently consists of five utilities operating in seven Midwestern states
AEP-KY	Kentucky Power d/b/a American Electric Power
AG	Attorney General, Commonwealth of Kentucky
Ancillary services	Those services necessary to support the transmission of energy and to maintain reliability, including voltage control, generation operating reserves and load balancing.
Baseload	The minimum energy level a company must provide on a constant basis to customers in its service territory.
Baseload generation, or baseload capacity	The generating equipment normally operated to serve loads on an around-the-clock basis.
Baseload plant	Power plant that typically uses low-cost fuel, allowing utilities to economically use that equipment a high percentage of the time. They typically have higher installation costs, but usually a lower overall cost of energy if used a high percentage of the time.
Big Rivers	Big Rivers Electric Corporation
Bulk power	Large amounts of wholesale power transferred across high voltage lines.
Bundling	Combining all costs into one rate, as opposed to separate charges for generation, transmission and energy services.
CAI	Commonwealth Associates, Inc.
Capacity	The limit at which a generator, turbine, transformer, transmission circuit, substation or system can produce or carry electricity for extended periods without failing.

CG&E	The Cincinnati Gas & Electric Company, the parent of The Union Light, Heat and Power Company
Cinergy	A public utility holding company - the parent of CG&E and Public Service Indiana.
Combustion turbines (CT)	An electric generator powered by gas or fuel oil, which often provides energy for peak loads. CTs typically have lower installation costs, but have higher fuel / operating costs.
Congestion	A condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously.
Contract path	The direct path along transmission wires between a seller and a buyer. It will not correspond to the actual flow of electricity, and it does not take into account that electricity flows through neighboring systems, which are not part of the contract.
Control areas	An electric power system that is charged by NERC with balancing load, generation and interchange schedules in a specific service territory.
Cooperative (Co-op)	A not-for-profit electric utility that is owned by and operated for the benefit of those using its service. There are 25 rural electric cooperatives in Kentucky that are supported by two generation and transmission cooperatives, East Kentucky Power in Winchester and Big Rivers Electric in Henderson, and TVA.
Demand Side Management (DSM)	Utility sponsored programs that influence the amount or timing of a customer's energy use. The use of management tools, such as conservation programs or incentives for reducing demand, that lower the demand for power during certain times of the day or week, or that shift the demand to times when demand is lower.
Demand	A term used generally to describe customers' power requirements.
Deregulation	Also called restructuring. The reorganization of traditional electric service to allow charges to be separated or "unbundled" into generation, transmission, distribution and other services. This may allow customers to buy electric service from competing providers at both the wholesale and retail levels.
Direct access	The ability of a customer to purchase electricity directly from a generator or the wholesale market, rather than through a local distribution utility.
Distribution	The portion of an electric system that delivers electric energy to a

system	customer's home or business through low-voltage lines.
Division of Energy	Kentucky Division of Energy
East Central Area Reliability Coordination Agreement (ECAR)	One of 10 regional reliability councils that comprise the North American Electric Reliability Council (NERC). It is charged with promoting the reliability and adequacy of power supply in its area. All Kentucky transmission-owning utilities are members of ECAR with the exception of TVA, which is a member of the Southeast Area Reliability Council (SERC).
East Kentucky	East Kentucky Power Cooperative, Inc.
Economy transactions	Sales of generation on an hourly basis, or the purchase of power when it is less expensive than one's own generation.
EEI	Electric Energy Inc.
EHV	Extra High Voltage
EIA	Energy Information Agency
Embedded costs	The cost of the existing electric system that is reflected in a utility's rate base.
End-use customer	A residential, commercial, agricultural or industrial customer who buys electricity to be consumed as a final product (not for resale).
Energy Board	Kentucky State Energy Policy Advisory Board
EPSA	Electric Power Supply Association
Exempt Wholesale Generator(EWG)	An independent, unregulated company that generates power solely for wholesale use and not to the public. Created by the Energy Policy Act of 1992.
FACTS	Flexible Alternating Current Transmission System
Federal Energy Regulatory Commission (FERC)	An independent regulatory agency within the U.S. Department of Energy that has jurisdiction over rates, terms and conditions of the transmission and wholesale sale of electricity between states.
FERC Order 888	Regulations issued by FERC to encourage wholesale competition in electricity. Owners of transmission grids must permit other parties to use the system to move wholesale electricity from

	generators to customers.
FERC Order 889	Regulations issued by FERC which require transmission system owners to make the availability and terms of transmission services available to the public concurrent with when such information is made known to the transmission system owners' generating and power trading business units and its affiliates.
FERC Order 2000	This 1999 order urged utilities with transmission to place their systems under the operational control of independent Regional Transmission Organizations (RTO).
Firm power	Contracted, wholesale power that must be delivered as agreed, even under adverse conditions.
Firm transmission service	Transmission service that has the highest priority. Long-term firm transmission service has the same priority as that of the transmission provider's own use of the transmission system.
Franchise customer, native load customer	The wholesale and retail customers within a transmission provider's service territory in which it has an obligation to serve.
Generation	The process of producing electrical energy.
Generator	A machine that converts mechanical energy into electrical energy.
Generation and transmission cooperative (G & T)	Not-for-profit organization that generates and transmits energy to distribution systems. The distribution system, which sells energy to retail customers, owns the G & T.
Grid	An electric system linking transmission lines, both regionally and locally.
Hydroelectric plant (Hydro)	A power plant in which turbine generators are driven by falling water.
Independent power producer (IPP)	An unregulated private entity that generates electricity and sells wholesale power to brokers and utilities.
Independent System Operator (ISO)	An independent, federally-regulated entity that coordinates regional transmission in a non-discriminatory manner and ensures the safety and reliability of the electric system.
Interchange schedule	An agreement between utilities on the amount of power that is to flow between the utilities.

Interchange transactions	Any transaction between wholesale suppliers of electricity.
Interruptible power	A special contract or tariff given to certain industrial customers that agree to have their service curtailed or temporarily suspended as part of an agreement with their electric provider.
Investor-owned utility (IOU)	An electric utility company owned and operated by private investors or stockholders. IOUs in Kentucky are Louisville Gas & Electric; Kentucky Utilities; The Union Light, Heat and Power Company, a subsidiary of Cinergy; and Kentucky Power Company, a.k.a. American Electric Power.
IRP	Integrated Resource Plan – written plan that shows an electric utility's forecast of future demand and its plans for acquiring the resources necessary to reliably meet that demand at the lowest reasonable cost consistent with sound operating practices.
Kilowatt (kW)	One thousand watts. The standard measure of electrical flow or power. Enough electricity to power ten 100-watt light bulbs.
KPE	Kentucky Pioneer Energy
Kenergy	Kenergy Corporation
LG&E/KU	Louisville Gas & Electric Company and Kentucky Utilities Company
Load	The amount of electric power required to meet customer's use in a given time period.
Load diversity	Reflects the fact that customers' electricity usage varies, depending upon the time of day, season, etc.
Market prices, market-based rates	A price set by the competitive market.
Megawatt (MW)	One thousand kilowatts. This term is generally used to measure the flows or capacity of power plants and transmission lines.
MEPAK	Municipal Electric Power Association of Kentucky
Merchant plant	A power plant built not to serve a geographic region but to sell bulk power to brokers and utilities, without its output necessarily being committed to long-term power contracts.

Midwest ISO	Midwest Independent System Operator
Municipal utility (MUNI)	A not-for-profit utility owned and operated by a municipal government in the community it serves. Municipal utilities serve Frankfort, Bowling Green, Owensboro and Bardstown, among other cities in Kentucky.
Native load	The electrical load in a utility's service territory used by its own customers. For a G & T cooperative, the electrical load in its member distribution cooperatives' service territories.
Non-firm power	Power available under a commitment having limited or no assured availability.
Non-firm transmission service	Transmission service available under a commitment having limited or no assured availability.
North American Electric Reliability Council (NERC)	A council formed in 1968 by the electric utility industry to promote the reliability and adequacy or bulk power supply in the electric utility systems of North America.
Obligation to serve	The regulatory obligation of a utility to provide electric service to any customer who seeks that service, and is willing to pay the rates for that service.
Off-system sale	Energy supplied outside a utility's service territory. For a G & T cooperative, energy supplied outside its member distribution cooperatives' service territories.
Open access	A regulatory mandate to allow others to use a utility's transmission and distribution facilities to move bulk power from one point to another on a nondiscriminatory basis for a cost-based fee.
OVEC	Ohio Valley Electric Corporation
Owensboro Municipal	Owensboro Municipal Utilities
Pancaked transmission rates	The effect of accumulating charges as power moves through each transmission system.
Parallel path flow	The flow of power on an electric system's transmission facilities, without compensation, resulting from a wholesale power contract

	between two other electric systems. Instead of taking the contract route, electricity will take the path of least resistance between seller and buyer, and may travel several parallel paths simultaneously.
Peak demand	The maximum load during a specified period of time.
Peaking unit	Generating equipment normally reserved for use during the hours of the highest daily, weekly or seasonal loads.
Point-to-point service	The transmission of energy from a designated point of receipt to a designated point of delivery.
Power marketer	An entity that takes title to electric power and then resells power to end-use customers.
Provider of last resort	A legal obligation to provide service to a customer where competitors have decided they do not want that customer's business.
PSI	Public Service Indiana
Rate base	The amount of money a regulated public utility has invested over the years in facilities (net of depreciation) which serves the customers, plus the amount of working capital required to cover the company's operating and maintenance expenses. The cost of plant, property and equipment which regulators allow regulated public utilities to recover through consumer rates.
Regional Transmission Organization (RTO)	A utility industry concept that the Federal Energy Regulatory Commission embraced for the certification of a regional organization that would be responsible for transmission planning and use on a regional basis.
Reliability	Electric system reliability has two components—adequacy and security. Adequacy is the ability of the electric system to supply to aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer services.
Reserve margin	The amount of unused available capability of an electric power system for a utility system as a percentage of total capability.

Restructuring	See deregulation.
Retail wheeling	Transmitting electricity from a wholesale supplier to a retail customer by a third party. This gives retail customers the ability to purchase electricity from sources they choose.
Return on equity (ROE) component	The return on investment that regulatory authorities allow investor-owned utilities.
Seam	The point of connection between two utilities or RTOs. Kentucky contains seams between the Midwest and Southeast RTOs.
Security coordinators	Individual utilities charged by NERC to manage the transmission system and ensure reliability.
Selective Catalytic Reduction (SCR)	Equipment used to remove nitrous oxides from the combustion gases of a boiler plant before discharge into the atmosphere.
SEPA	Southeast Power Administration
Service territory	The geographic area served by a utility.
Spot market	Short-term (hourly, daily, weekly) purchases of electricity from the wholesale market.
Substation	Equipment that switches, changes or regulates electric voltage.
State Data Center	Kentucky State Data Center at University of Louisville
Stranded costs	Prudent costs incurred by a utility, which may not be recoverable under market-based retail competition. Examples are undepreciated generating facilities, deferred costs, and long-term contract costs.
Tariff	A document that lists the terms, conditions and prices under which utility services like transmission will be provided. Approved by a regulatory agency.
Tennessee Valley Authority (TVA)	A federal corporation and the country’s largest public power company, serving Tennessee and portions of six other states, including several counties in south central and western Kentucky.
TLR	Transmission Loading Relief

Transmission	The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.
Transmitting utility	Any utility transmitting wholesale, high-voltage electrical energy. A transmitting utility can be for-profit, or in the case of cooperatives, not-for-profit.
TRANSCO	A regulated, for-profit company that owns, constructs and maintains wires used to transmit wholesale power, and does not own any generation or distribution facilities.
ULH&P	The Union Light, Heat and Power Company
Unbundled rates or service	Electric service broken down into its basic components. Each component is priced and sold separately. For example, generation, transmission and distribution could be unbundled.
Wheeling	The transportation of electricity by an entity that does not own or directly use the power it is transmitting.
Wholesale transactions	The purchase and sale of electricity from generators to organizations that sell to retail customers.