COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

O R D E R

On February 7, 2005, Governor Ernie Fletcher issued Executive Order 2005-121, which directed the Commission to report on the future needs for electricity in the Commonwealth. The report was to include a "Strategic Blueprint"[1] to "promote future investment in electric infrastructure in the Commonwealth of Kentucky, to protect Kentucky's low-cost electric advantage, to maintain affordable electricity rates for all Kentuckians and to preserve Kentucky's commitment to environmental protection."[2] The Executive Order directed the Commission to analyze the Commonwealth's projected needs for new electric generation, transmission and distribution, and to specifically review the following: the current status of generation, transmission and distribution facilities; available sources of electricity supply; projected demand through 2025; the existence of barriers to investment in generation, transmission and distribution; barriers to the utilization of technologies in generation, transmission and distribution; strategies for the utilization of technologies to improve the efficiency of electricity service; opportunities to promote utilization of renewable resources; and any

[1] Executive Order 2005-121, February 7, 2005, at 2.

[2] Id.

other information to "help ensure future investment in electricity infrastructure to meet Kentucky's needs."[3]

In response to that Executive Order, the Commission initiated this proceeding by Order dated March 10, 2005, noting that it had addressed similar issues in 2001 in Administrative Case No. 387.[4] In addition, the Commission initiated a vulnerability assessment of Kentucky's electric transmission system following the electric blackout of August 14, 2003 and stated that the results of that assessment would be considered in preparing the report for the Governor.

All of Kentucky's jurisdictional electric utilities, generation and distribution, were made parties to this proceeding and directed to respond to an extensive data request. The municipal electric systems, the Tennessee Valley Authority ("TVA"), TVA distribution cooperatives, independent power producers, and other parties likely to have an interest in energy issues were invited to intervene and participate.

Intervening in this proceeding were the Attorney General of the Commonwealth of Kentucky ("AG"), Kentucky Industrial Utility Customers, Inc. ("KIUC"), Alcan Primary Products Corporation ("Alcan"), Century Aluminum of Kentucky, LLC ("Century"), and the Municipal Electric Power Association of Kentucky ("MEPAK"). Although TVA did not intervene, it filed on behalf of itself and its Kentucky distributors, information responsive to the Commission's data request and comments at a technical conference.

[3] Id.

[4] Administrative Case No. 387, A Review of the Adequacy of Kentucky's Generation Capacity and Transmission System, Order dated December 20, 2001.

The vulnerability assessment was filed in the record of this case on April 28, 2005. All utilities that participated were ordered to certify that they have reviewed the assessment and taken appropriate action to address identified vulnerabilities. All such certifications have been received.

An initial data request was included as part of the Commission's March 10, 2005 Order and a second data request focused on limited issues with certain utilities was issued on April 28, 2005. In response to a motion filed by Alcan and Century, Big Rivers Electric Corporation ("Big Rivers") and Kenergy Corp. ("Kenergy") were ordered to respond to certain questions by Order issued May 27, 2005. All responses to data requests have been filed.

The Commission held a technical conference on June 14, 2005 for the purpose of receiving comments from utilities, intervenors, persons likely to be interested in energy issues, and the general public. Those that filed written comments and participated at the technical conference included Big Rivers, East Kentucky Power Cooperative, Inc., Kentucky Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, The Union Light, Heat and Power Company, Meade County Rural Electric Cooperative Corporation on behalf of the jurisdictional distribution cooperatives, Kentucky Pioneer Energy, MEPAK, PJM Interconnection, TVA, the Kentucky Resources Council, KIUC, Alcan and Century, the AG, the Environmental and Public Protection Cabinet, Energy Systems Group, LLC, Peabody Energy Corp., Moore Environmental, Geoff Young, and Dr. Donald G. Colliver. The Midwest Independent System Operator, Inc. also submitted written comments but did not otherwise participate at the technical conference.

The procedural schedule did not provide for briefs and all responses to data requests made at the technical conference have been filed.

The report required by the Executive Order, *Kentucky's Electric Infrastructure: Present and Future,* was submitted to Governor Fletcher on August 22, 2005 and is attached hereto as Appendix A. In accordance with the Executive Order, the report includes the Commission's appropriate conclusions and recommendations relative to Kentucky's future energy policy.

A "summary of proceedings," which summarizes the detailed information contained in the data responses and the filed comments of the participants, is attached hereto as Appendix B.

The Commission finds that this administrative case should be closed and removed from the docket.

IT IS THEREFORE ORDERED that Administrative Case No. 2005-00090 is closed.

Done at Frankfort, Kentucky, this 15th day of September, 2005.

By the Commission

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2005-00090 DATED September 15, 2005

Kentucky's Electric Infrastructure: Present and Future

An Assessment Conducted

Pursuant to

Executive Order 2005-121

by the

Kentucky Public Service Commission

August 22, 2005

Kentucky
UNBRIDLED SPIRIT

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Participants

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The Attorney General of the Commonwealth of Kentucky
Benton Electric System
Berea Municipal Utilities
Big Rivers Electric Corporation
Big Sandy RECC
Blue Grass Energy
Bowling Green Municipal Utilities
The City of Paris
Century Aluminum of Kentucky, LLC.
Clark Energy
Cumberland Valley Electric
Dr. Donald G. Colliver
East Kentucky Power Cooperative, Inc.
Electric Plant Board of the City of Vanceburg
Energy Systems Group, LLC.
Farmers RECC
Fleming-Mason Energy
Frankfort Plant Board
Geoff Young
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Moore Environmental
The Municipal Electric Power Association of Kentucky
Nolin RECC
Owen Electric
Peabody Energy
Pennyrile Electric
PJM Interconnection
Princeton Electric Plant Board
Russellville Electric Plant Board
Salt River Electric
Shelby Energy
South Kentucky RECC
Taylor County RECC
The Tennessee Valley Authority
Tri-County EMC
The Union Light, Heat and Power Company
Warren RECC

The participant list includes the entities that responded to data requests, provided comments for the technical conference or both.

Executive Summary

This report was prepared in response to Executive Order 2005-121, issued on February 7, 2005 by Governor Ernie Fletcher, directing the Kentucky Public Service Commission (Commission) to report on the future needs for electricity in Kentucky.

The Executive Order called for a "Strategic Blueprint" to "promote future investment in electric infrastructure in Kentucky, to protect Kentucky's low-cost electric advantage, to maintain affordable electricity rates for all Kentuckians and to preserve Kentucky's commitment to environmental protection." The Commission was directed to identify projected needs for new electric generation, transmission and distribution; barriers to investment in electric infrastructure; barriers to the utilization of new technologies; opportunities to promote utilization of renewable resources; and other information necessary to "help ensure future investment in electricity infrastructure to meet Kentucky's needs."

In response, the PSC collected information and comments from Commission jurisdictional utilities, non-jurisdictional utilities, independent power producers, and those with an interest in energy policy. A list of participants is on page 4.

PRESERVING KENTUCKY'S LOW ELECTRIC RATES

Kentuckians pay the lowest electricity rates in the nation. In 2005, the average retail rate for electricity in Kentucky is 4.47 cents per kilowatt-hour (kWh), 40 percent below the national average rate of 7.52 cents/kWh. These low electricity prices have been a major factor in promoting economic development and growth.

Kentucky's low electricity rates are the result of investment by Kentucky's utilities in large, coal-fired generating units - which generate 95 percent of Kentucky's electricity - combined with an abundant local fuel supply, sound utility management and a statutory system that regulates the price jurisdictional utilities may charge for retail electricity

Kentucky and the United States as a whole have ample coal reserves. Coal will continue to supply the majority of the nation's electricity through 2025. But a number of uncertainties could affect Kentucky's long-term ability to ensure low electricity rates. These include federal policies regarding the development of regional electricity markets and air emission standards, factors affecting coal production and the price of coal.

The Commission is concerned that federal decisions and those of states that have moved away from traditional electric utility regulation may have negative impacts on Kentucky's transmission and generating facilities. As transmission requirements imposed from outside the state increasingly affect Kentucky, the Commonwealth is threatened with diminished control of a resource constructed for and paid for by Kentucky's electric customers.

KENTUCKY'S ELECTRIC INFRASTRUCTURE

Kentucky's jurisdictional electric utilities serve about 1.8 million customers. Thirty municipal electric systems and five distribution cooperatives supplied by the Tennessee Valley Authority are not subject to Commission jurisdiction. The non-jurisdictional electric utilities serve about 375,000 customers.

The Commission has determined that Kentucky's electric utilities, both jurisdictional and non-jurisdictional, have adequate generation infrastructure to serve their current customers and have demonstrated that they are adequately planning to serve the needs of their customers through 2025. Kentucky's peak electricity is expected to grow to an average rate of 1.7% requiring approximately 7,000 MW of additional generation by 2025 to maintain an adequate supply. It is also important to note all of the jurisdictional generating utilities currently rely on generation capacity that has been in operation for 35 years or more while none of the utilities indicated that they have plans to retire any of their older generating facilities, the Commission intends to require the jurisdictional utilities to address issues relating to their older generating units in their future planning.

Kentucky's electric transmission system is highly reliable to serve Kentucky customers. However, it is limited in the amount of power it can transfer through the state, particularly north and south.

Kentucky's electric transmission system is actually seven individual systems that are interconnected at numerous points throughout the state. The interconnections were initially intergraded to provide mutual reliability benefits, load diversity, and to reduce the occurrence of redundant facilities, but now are expected to transfer large blocks of power between utilities and states.

With the growth of the competitive wholesale market for electricity, the transmission system is now being called upon to provide interstate transfers – a purpose for which it was not designed. Power transfers from north of Kentucky to south of Kentucky, and vice versa, are limited due in part to the weak interconnection of the transmission systems.

While additional transmission interconnections are not needed for Kentucky's utilities to reliably and economically serve their customers, improving these interconnections may make it more feasible for Kentucky's utilities to increase off-system sales and for independent power producers to locate in Kentucky. There is much debate concerning how to allocate the costs of such improvements. Kentucky should remain engaged in this debate at the FERC and with the Regional Transmission Organizations (RTOs).

The Comprehensive Energy Bill signed into law by President Bush on August 8, 2005 contains provisions regarding the siting of the nation's bulk transmission grid. The provision may impact Kentucky's ability to regulate the siting of transmission lines within our borders.

The bill requires the Department of Energy to designate "national interest electric transmission corridors." Kentucky's location between northern and southern load centers, coupled with the constraints on north-south power transfers within Kentucky, present the possibility that one or more "national interest electric transmission corridors" through Kentucky will be identified. That designation will give the Federal Energy Regulatory Commission (FERC) siting jurisdiction for facilities within that corridor if the state does not act within one year. Kentucky should take steps to protect the interests of the Commonwealth in this process. Kentucky should also revisit its transmission siting statutes to ensure that they mesh with the energy bill provisions.

Ensuring reliability of retail service requires adequately maintaining distribution infrastructure, particularly managing vegetation in rights of way (ROW). Effective ROW management - cutting trees or branches which may come into contact with distribution lines - can reduce outages and restoration time during severe weather.

Kentucky has no regulations setting specific parameters for ROW maintenance. The jurisdictional utilities have expressed their opposition to such a standard, in large part because of the difficulties they encounter with property owner's desire to leave their trees undisturbed. The Commission recognizes these difficulties, but is concerned that the reluctance of some property owners to allow proper trimming of their trees lessens the reliability of entire distribution systems.

Establishment of an ROW clearance standards could provide utilities with the means to ensure proper maintenance and improve the reliability of electric service. Therefore, the Commission believes that further consideration should be given to the establishment of some practical distribution ROW clearing parameters for Kentucky's jurisdictional electric distribution utilities.

CONSERVATION, ENERGY EFFICIENCY AND ENVIRONMENTAL PROTECTION

As Kentucky's generating fleet ages, and as environmental requirements become more restrictive, energy conservation, the use of renewable energy sources, and alternative generation technology will play an increasingly important role in Kentucky.

Kentucky's jurisdictional utilities have established a number of demand-side management (DSM) programs to encourage energy conservation and defer the need to construct new generating capacity. However, because of relatively low electric rates, DSM has not yet proven to be as cost-effective in Kentucky as in other regions.

Several Kentucky electric utilities currently offer their customers the option of purchasing "green power," which is derived from renewable sources. However, due to the high cost to generate power from most renewable resources, "green power" is sold at a premium price. The Commission believes that it is important to encourage utilities to expand the use of renewables and reduce the cost of "green power". Kentucky's energy policy should include incentives to use renewable energy and an effort to educate the public regarding the benefits of renewables.

Financial incentives similar to those that may be developed for renewables should be available for coal gasification, which will enable the continued use of Kentucky coal while reducing the associated air emissions. Incentives could include tax credits, grants and low interest loans.

The Commission believes that Kentucky's environmental policy should be balanced. We encourage the electric utilities, state regulatory agencies and interested organizations to participate at the state and federal level to ensure that sound environmental policy is developed.

REGULATORY CONCERNS

In addition to concerns noted earlier, the Commission notes several regulatory issues affecting Kentucky's electric utilities.

At the state level, a change in tax policy has the potential to significantly impact all jurisdictional electric utilities. The Kentucky Revenue Department has begun subjecting distribution and substation transformers to sales tax. One utility noted that it has been assessed almost $2 million for the period from February 1, 2001 through November 30, 2004.

The increase in taxes assessed to regulated electric utilities will increase the cost to serve customers and will eventually result in higher rates. The Commission recognizes the responsibility of all citizens and companies to bear their fair share of Kentucky's tax burden. Therefore, the Commission recommends that this issue be considered in Kentucky's energy policy in the context of its overall impact on both electricity rates and taxes.

Federal energy policy has been moving toward a competitive market for electricity generation since the 1990's. RTOs now operate energy markets in addition to their initial role of operating transmission systems regionally. Several states have restructured their electric industry to a competitive model. Kentucky has not. Kentucky will be impacted by the federal legislation and federal actions. The Commission believes that its regulatory structure has enabled it to have the lowest cost power in the nation and that Kentucky should preserve its current statutory and regulatory framework, which focuses on the utilities' obligation to serve their customers within a defined service territory. Kentucky must insist on full participation in any federal decisions and work diligently to maintain its status as a low cost energy state.

The Commission recognizes that changes within the electric industry in recent years have increased uncertainty. However, the regulatory scheme in Kentucky has proven successful, due to the measured and deliberate approach that has been taken to address various issues. The Commission does not intend to suggest regulatory stagnation. Rather, in light of today's greater uncertainty, we believe it is our responsibility to seek ways to improve the existing regulatory framework.

Because the U.S. electric power industry is changing, Kentucky should consider policies to protect or insulate Kentucky ratepayers from market uncertainties and the price implications of future environmental restrictions. Given the economic benefits of Kentucky growing as an energy exporter, Kentucky policy makers should also give consideration to opportunities for Kentucky citizens, businesses, and communities to benefit from greater participation in energy markets. In either case, a balanced approach will be necessary to preserve Kentucky's low-cost energy, responsibly develop Kentucky's energy resources, and preserve Kentucky's commitment to environmental quality.

Among the immediate uncertainties facing the electric power industry in Kentucky are: federal policies regarding the development of regional electricity markets and air emission standards; the ability to site new electric generation and transmission facilities; factors affecting coal production and the price of coal; and technologies that will improve the efficiency of electricity production and use. Policy and technological developments with regard to these issues will directly affect electricity rates in Kentucky. Given the importance of low electricity rates for Kentucky, both as a tool for recruiting and retaining businesses, as equally as a necessity for all its citizens, the Commonwealth must continually evaluate its policies to mitigate the risks associated with generating, transmitting and distributing electricity.

Procedural Background

This report has been prepared pursuant to Executive Order 2005-121 issued on February 7, 2005 by Governor Ernie Fletcher. In that Executive Order, Governor Fletcher directed the Commission to report on the future needs for electricity in the Commonwealth. The report was to include a "Strategic Blueprint" to "promote future investment in electric infrastructure in the Commonwealth of Kentucky, to protect Kentucky's low-cost electric advantage, to maintain affordable electricity rates for all Kentuckians and to preserve Kentucky's commitment to environmental protection."

In the Executive Order's directive to analyze projected needs for new electric generation, transmission and distribution, the Commission was to include the following: the current status of generation, transmission and distribution; available sources of electricity supply; projected demands through 2025; the existence of barriers to investment in generation, transmission and distribution; barriers to the utilization of technologies in generation, transmission and distribution; strategies for the utilization of technologies to improve the efficiency of electricity service; opportunities to promote utilization of renewable resources; and any other information to "help ensure future investment in electricity infrastructure to meet Kentucky's needs."

In response to that Executive Order, on March 10, 2005, the Commission initiated Administrative Case No. 2005-00090 to assist it in gathering the information necessary to complete the report. All of Kentucky's jurisdictional electric utilities were made parties to this proceeding and directed to respond to an extensive data request from the Commission Staff. Notice of this proceeding was given to the non-jurisdictional electric utilities serving Kentucky customers, independent power producers with sites in Kentucky, and persons likely to have an interest in energy issues. The Tennessee Valley Authority (TVA) responded to Staff's data request on its behalf and on behalf of the five distribution cooperatives it currently serves. Three of those distribution cooperatives, Pennyrile Electric, Tri-County Electric Membership Corporation (Tri-County) and Warren Rural Electric Cooperative Corporation (Warren RECC), also submitted their own responses to the Staff's data request. The Municipal Electric Power Association of Kentucky (MEPAK) also responded to a data request on behalf of its members.

The record also included a highly technical vulnerability assessment of Kentucky's electric transmission system. The study was performed to determine whether Kentucky's transmission facilities could withstand the events that caused the widespread electric blackout of August 14, 2003. The results of that assessment have been considered by the Commission and briefly addressed in this report.

The Commission's Statutory Limitations

It is important to note that the scope of this proceeding and the report is responsive to the assessment required by the Governor's Executive Order but goes beyond the traditional duties of the Commission. The information provided by the participants has not been subject to the same scrutiny had the scope of this proceeding been focused solely on issues subject to Commission regulation. In that regard, we find no reason to doubt the accuracy of the factual information presented.

Even though the comments of some parties are diametrically opposite those of other parties, we have considered all comments in the development of this report. As set forth in the *Comprehensive Energy Strategy* and the Executive Order, this assessment is to serve as the "strategic blueprint" for policy makers. This report identifies and gives perspective to the issues that should be considered in developing a detailed, statewide energy policy.

Format of the Report

This report includes the conclusions and recommendations of the Commission as appropriate. The adequacy of Kentucky's generation, transmission and distribution resources is addressed first, followed by a discussion of the major issues facing the electric utility industry, the barriers they may face, the other issues identified in the Executive Order and other related issues that arose during the proceeding.

A "summary of the proceedings," which discusses the detailed information submitted in response to data requests and the comments of the participants has also been prepared. The "summary of proceedings" can be accessed at the Commission's Website at psc.ky.gov.

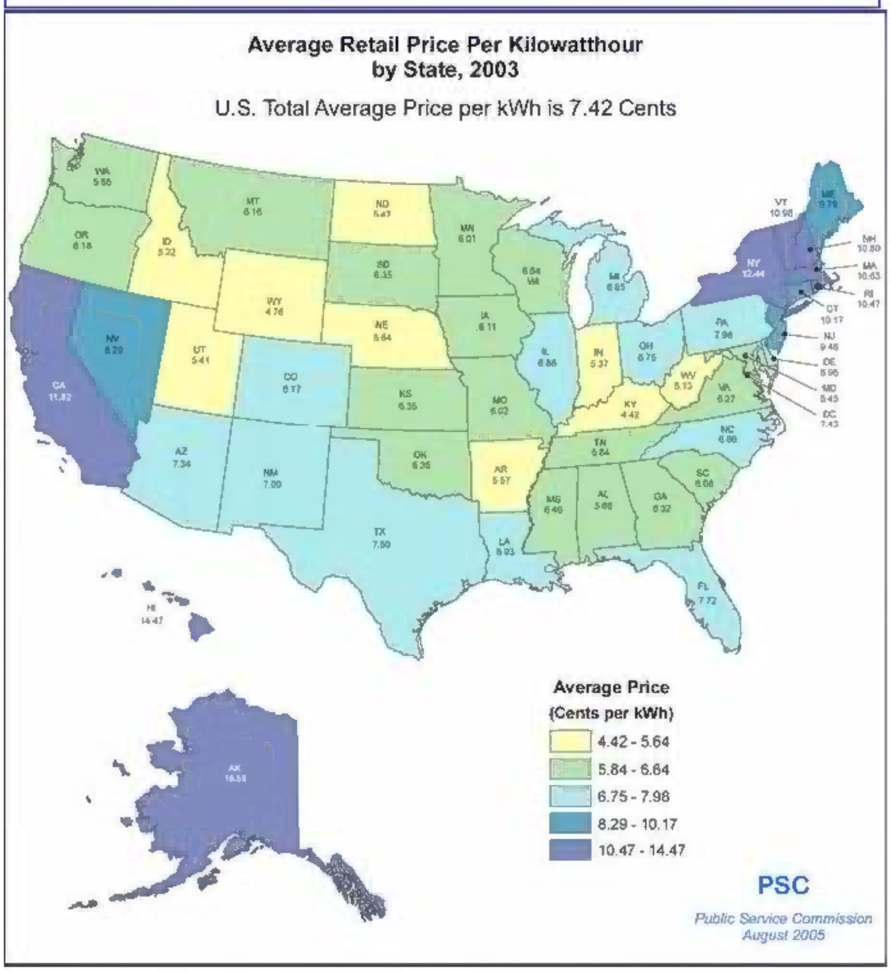
Introduction

Kentuckians, on average, pay the lowest electricity rates in the nation. According to U.S. Department of Energy (DOE) statistics for 2005, the average retail rate for electricity in Kentucky is 4.47 cents per kilowatt-hour (kWh), as compared to the national average rate of 7.52 cents per kWh. Over the past 15 years, only a few states in the Northwest (Idaho, Wyoming, Montana and Washington) and nearby West Virginia have been able to offer consumers and businesses electricity rates comparable to those available in Kentucky.

The reasons for Kentucky's low electricity rates, as compared to other states, are varied. Primarily, they result from historic investments by Kentucky's utilities in large, coal-fired generating units. Kentucky is among the top three coal producing states in the nation, and coal is used to produce approximately 95 percent of Kentucky's electricity. As a result of these historic investments, combined with an abundant local fuel supply, sound utility management and a statutory system that regulates the price jurisdictional utilities may charge for retail electricity, electricity prices in Kentucky are extremely competitive and favorable to economic development and growth.

Utilizing current technology and projected production rates, DOE estimates that the

Kentuckians, on average, pay the lowest electricity rates in the nation.

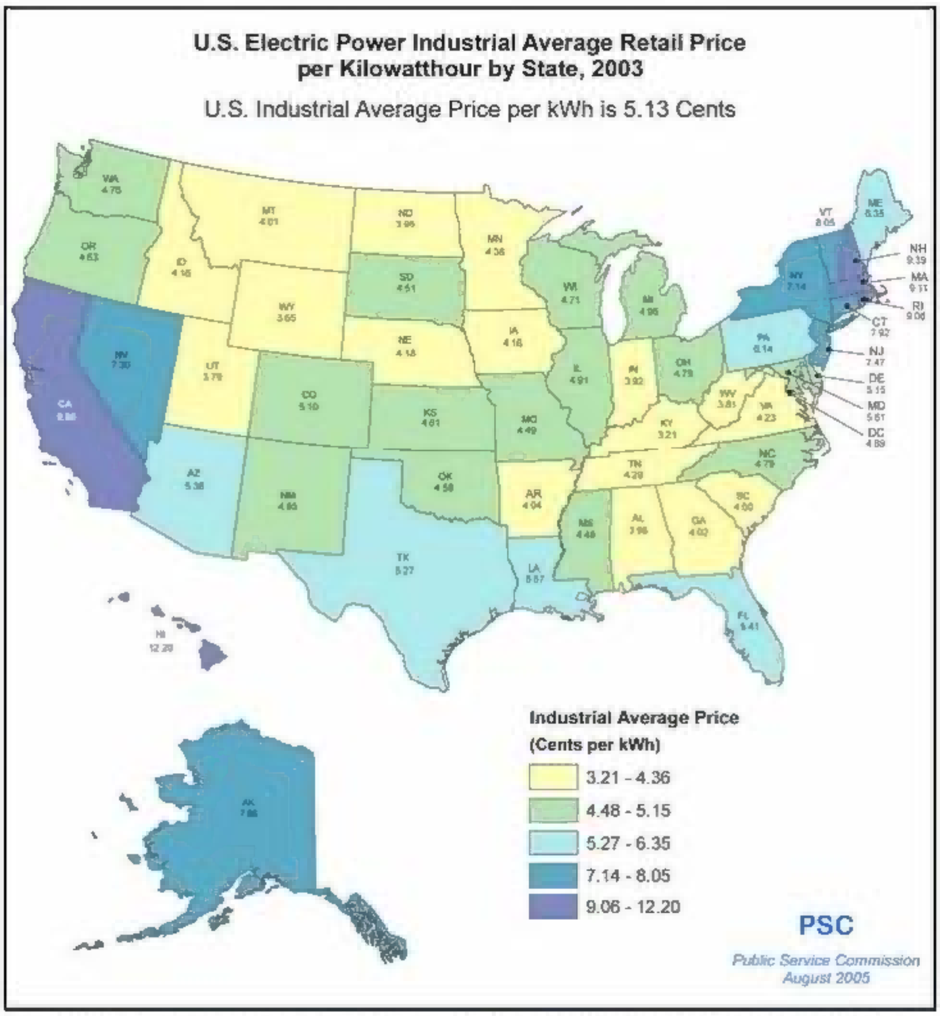


Source: Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Data".

United States has a 250-year supply of coal to meet projected demand. Moreover, the United States is projected to continue to rely on coal to provide more than 50 percent of the nation's electricity through 2025. While this bodes well for Kentucky's near-term electricity price and supply, a number of uncertainties could affect Kentucky's long-term ability to ensure low electricity rates. These uncertainties pose a risk to Kentucky electricity consumers and will require policy makers to periodically evaluate Kentucky's regulatory model and long-term reliance on conventional coal-fired generation to meet electricity demand.

Among the immediate uncertainties facing the electric power industry in Kentucky are: federal policies regarding the development of regional electricity markets and air emission standards, factors affecting coal production and the price of coal, and technologies that will improve the efficiency of electricity production and use. Policy and technological developments with regard to these issues will directly affect electricity rates in Kentucky.

Given the importance of low electricity rates for Kentucky, not only as a necessity for all its citizens, but also as a tool for attracting and retaining businesses, the Commonwealth must continually evaluate its policies to mitigate, where possible, those factors that pose a risk to the ability of utilities in Kentucky to generate, transmit and distribute low-cost, reliable electricity.



Source: Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Data".

Resource Adequacy– Generation

As discussed in more detail below, Kentucky has six major jurisdictional electric utilities that own or are in the process of acquiring generation. They include four investor-owned utilities: Kentucky Power Company (Kentucky Power); Kentucky Utilities Company (KU); Louisville Gas and Electric Company (LG&E); the Union Light, Heat and Power Company (ULH&P), and two generating and transmission cooperatives (G&Ts): Big Rivers Electric Corporation (Big Rivers) and East Kentucky Power Cooperative, Inc. (East Kentucky Power). Collectively, Kentucky's jurisdictional electric utilities serve about 1.8 million customers. There are also 30 municipal electric systems and five TVA supplied distribution cooperatives, which provide retail electric service that are not subject to the Commission's jurisdiction. TVA owns generation in Kentucky and serves a limited number of retail customers in western Kentucky. The non-jurisdictional electric utilities serve about 375,000 customers.

The peak electricity demand projection for Kentucky consumers for 2005 is in excess of 15,500 MW and is expected to grow at an average annual rate of 1.7 percent reaching 21,900 MW by 2025. As discussed later in this report, these projections take into account expected gains in energy efficiency. Approximately 7,000 MW of generation will need to be added over the next 20 years to meet this growing demand and maintain a reliable reserve margin. Presumably, the added generation will primarily be base load capacity with a small proportion being peaking capacity.

With regard to generation resource planning, Administrative Regulation 807 KAR 5:058 requires the six major jurisdictional electric utilities in the Commonwealth to file triennial integrated resource plans (IRPs) with the Commission, for review and evaluation by the Commission's Staff. The intent of the IRP process is to ensure that all reasonable options for the future supply of electricity are being considered, and that customers will be provided an adequate and reliable supply of electricity at the lowest reasonable cost.

The IRP process requires each major electric utility to forecast its customer demand and energy levels for a 15-year planning horizon, evaluate the adequacy of its generation supply and demand-side resources, determine the need for additional generating resources, and select the optimal mix of resources to meet the future needs of its customers. The Commission Staff reviews and critiques each of the six IRPs in a staff report, which provides recommendations for future IRP filings.

The Commission does not issue a formal decision on the adequacy of the IRPs, but since its inception in 1990, the IRP process has been very helpful in alerting the Commission to emerging issues and keeping the Commission apprised of the utilities' projected needs and future plans. As part of the Commission's monitoring and regulation of electric utilities, the IRP process is a helpful tool which the Commission expects will continue to provide benefits on a going-forward basis.

With respect to the non-jurisdictional electric utilities, they are not required to prepare formal IRPs. However, the record shows that they do perform similar planning studies. The models they utilize may have different names, but they are essentially the same. Also, the data inputs for the models are from the same or similar sources, and the output or results of their models are analyzed and reviewed by knowledgeable energy experts. In several instances, the planning for the non-jurisdictional utilities is performed by the same individuals that perform these duties for the jurisdictional utilities.

The Commission has determined that Kentucky's electric utilities, both jurisdictional and non-jurisdictional, have adequate generation infrastructure to serve their current customers and have demonstrated that they are adequately planning to serve the needs of their customers through 2025. The jurisdictional utilities' long-range planning includes peaking generation, which consists primarily of gas-fired combustion turbines (CTs), and base load generation, which consists primarily of pulverized or fluidized bed coal-fired generation. To varying degrees, the jurisdictional utilities also include power purchases in their supply portfolios for serving their customers' future needs.

Although they are adequately planning to serve their customers' future needs, it is important to note all of the jurisdictional generating utilities own, or in the case of ULH&P, will soon own, generation capacity that has been in operation in excess of 35 years. While some of this generation has been operating for 40 to 50 years, none of the utilities indicated that they have plans to retire any of their older generating facilities, although several indicated that it is a possibility. The Commission does not fault the utilities for not having any plans for retirement of facilities that have been well maintained, upgraded and operated properly; however, we are mindful of the potential for failure of older units. Therefore, we will require that each of the jurisdictional generating utilities address issues relating to their older generating units in their next scheduled IRP filing.

(For Big Rivers, which no longer operates its generation, we will expect a summary overview of scheduled and unscheduled outages for all of the generation operated by Western Kentucky Energy (WKE) for the three most recent calendar years along with a summary of all environmental equipment that has been installed on each unit.)

A summary discussion of the information compiled on the generation and supply resources and planning and reserve requirements is provided in the discussion for each jurisdictional generating utility and for the non-jurisdictional electric utilities as a whole.

Tables listing the jurisdictional and non-jurisdictional generating units sited in Kentucky and a map showing the generating sites follow.

Electric Generation in Kentucky

Jurisdictional Generation

East Kentucky Power Cooperative, Inc.

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Dale	Clark	four	196	coal	1954-1960
Cooper	Pulaski	two	341	coal	1965, 1969
Spurlock	Mason	three	1,459	coal	1977, 1981, 2005
Smith CTs	Clark	seven	842	gas	1999, 2001, 2005
Bavarian Landfill	Boone	one	3	methane	2004
Green Valley Landfill	Greenup	one	2	methane	2004
Laurel Ridge Landfill	Laurel	one	3	methane	2004

Kentucky Power Company

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Big Sandy RECC	Lawrence	two	1,060	coal	1963, 1969

Kentucky Utilities Company

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Dix Dam	Garrard	three	24	hydro	1925
E.W. Brown	Mercer	three	697	coal	1957, 1963, 1971
E.W. Brown	Mercer	seven	849	gas	1994-2001
Ghent	Carroll	four	1,945	coal	1974-1984
Green River	Muhlenberg	two	163	coal	1954, 1959
Haefling	Fayette	three	36	gas	1970
Lock 7	Mercer	three	NA	hydro	1927
Tyrone	Woodford	two	58	oil	1947-1948
Tyrone	Woodford	one	71	coal	1953

Electric Generation in Kentucky

Jurisdictional Generation

Louisville Gas and Electric Company

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Cane Run	Jefferson	three	563	coal	1962-1969
Cane Run	Jefferson	one	14	gas	1968
Mill Creek	Jefferson	four	1,472	coal	1972-1982
Ohio Falls	Jefferson	eight	48	hydro	1928
Paddys Run	Jefferson	three	193	gas	1968, 2001
Trimble County	Trimble	one	383	coal	1990
Trimble County	Trimble	six	960	gas	2002, 2004
Waterside	Jefferson	two	22	gas	1964
Zorn	Jefferson	one	14	gas	1969

The Union Light, Heat & Power Company

Generating Station	County	No. Units	MW	Fuel	Initial Operation
East Bend	Boone	one	414	coal	1981

NOTE: ULH&P should close the transaction to acquire this generation later in 2005. The other generating units it will acquire are Miami Fort 6 and Woodsdale 1-6, which are located in Ohio.

Electric Generation in Kentucky

Non- Jurisdictional Generation

Municipal Generation

Generating Station	County	No. Units	MW	Fuel	Initial Operation
HMP&L – Station 1	Henderson	two	2	gas	1948
HMP&L – Station 1	Henderson	two	44	coal	1956, 1968
OMU – Smith Station	Daviess	two	425	coal	1964, 1974
City of Paris	Bourbon	seven	12	fuel oil	1934-1974

Federally-owned Generation

Tennessee Valley Authority

Generating Station	County	No. Units	MW	Fuel	Initial Operation
TVA - Paradise	Muhlenberg	three	2,331	coal	1963, 1970
TVA - Shawnee	McCracken	ten	2,611	coal	1953-1956
TVA – Kentucky Dam	Livingston	five	197	hydro	1944-1948
USACE – Laurel Dam	Laurel	one	70	hydro	1977
USACE – Barkley Dam	Lyon	four	130	hydro	1966
USACE – Wolf Creek Dam	Russell	six	270	hydro	1951-1952

Electric Generation in Kentucky

Non- Jurisdictional Generation

Merchant Generation

Dynegy

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Dynegy – Foothills	Lawrence	two	460	gas	2002
Dynegy - Riverside	Lawrence	three	690	gas	2001
Dynegy – Bluegrass	Oldham	three	624	gas	2002

Western Kentucky Energy

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Reid	Webster	one	65	coal	1966
Coleman	Hancock	three	455	coal	1969-1972
HMP&L Station 2	Webster	two	405	coal	1973-1974
Reid CT	Webster	one	65	fuel oil	1976
Green	Webster	two	454	coal	1979-1981
Wilson	Ohio	one	420	coal	1986

Cogeneration Generation

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Cinergy – Silver Grove	Campbell	one	20	gas	2001
Weyerhauser – Ky. Mills	Hancock	one	88	wood waste	2001
Cox – Waste to Energy	Taylor	one	4	wood waste	1995
Air Products – Calvert City	Marshall	one	27	gas	2000

Big Rivers - Resource Summary

Existing Generation/Supply Resources

Big Rivers is a not-for-profit G&T which provides power at wholesale to three member/owner distribution cooperatives, Jackson Purchase Energy Corporation (Jackson Purchase), Kenergy Corporation (Kenergy), and Meade County RECC. These distribution cooperatives provide retail electric service to approximately 107,000 customers in 22 western Kentucky counties. As part of an agreement arising from its 1996 bankruptcy filing, Big Rivers leases all of its generating facilities to WKE, an unregulated affiliate of LG&E and, in a companion transaction, purchases power from LG&E Energy Marketing, Inc. (LEM), another unregulated affiliate of LG&E, through 2022.

Big Rivers historically had the largest industrial load of any G&T because it supplied power to two aluminum smelters, Alcan Primary Products Corporation (Alcan) and Century Aluminum of Kentucky, LLC. (Century). However, as part of its reorganization, the smelters' firm loads are now supplied by LEM under separate power contracts with Kenergy. (*The issue of the continued provision of service to the smelters beyond the expiration of their contracts in 2010 and 2011 was raised by Alcan and Century in this proceeding and is discussed in the Rate Certainty, Cost Recovery and Other Regulatory Issues section.)*

Currently, Big Rivers has 597 megawatts (MW) available from LEM plus 178 MW available from the Southeast Power Administration (SEPA), through the U.S. Army Corps of Engineers, for a total of 775 MW. In 2012, Big Rivers' capacity will increase to 978 MW, with 800 MW available from LEM along with the 178 MW available from SEPA.

Resource Planning

Resource planning is integral to Big Rivers' overall planning processes. Like the other major jurisdictional utilities, Big Rivers files its IRPs with the Commission on a triennial basis. Big Rivers assists its three member/owner distribution cooperatives in determining their overall power requirements and combines those requirements to arrive at the Big Rivers system's annual load forecast for a 15-year planning horizon. Big Rivers determines the amount of supply resources required for each year. It compares these requirements with the resources available under existing, firm power supply contracts to assure sufficient power is available to meet its obligations to its members.

Big Rivers and its member distribution cooperatives screen Demand-Side Management (DSM) measures through cost/benefit analyses to determine acceptable DSM measures to initiate. Big Rivers provides financial participation (in the form of end-user incentive payments) and technical support to its distribution cooperatives for the following programs: (1) Add-on heat pump; (2) All Electric Touchstone Energy Home; and (3) Electric water heater. Not all Big Rivers' distribution cooperatives offer all programs. A detailed discussion of Big Rivers' DSM programs and the energy efficiency related services available to residential, commercial and industrial services through Jackson Purchase, Kenergy, and Meade County RECC is included in the Energy Efficiency, Demand-Side Management and Conservation section.

Big Rivers' budgets for the incentive programs are shown below:

2005	2006	2007 and beyond
$136,950	$174,250	$255,500

Resource Adequacy

As noted above, through 2011, Big Rivers will have 775 MW of generation available from LEM and SEPA. During this period, its base case forecast projects native load demand to reach 703 MW, while its high case demand forecast is 728 MW, either of which can be met under Big Rivers' power supply contracts. Beginning in 2012, Big Rivers will have 978 MW in generation available from LEM and SEPA. In 2017, the last year in Big Rivers' forecast horizon, its base case forecast projects native load demand to be 780 MW. Under its high case forecast, Big Rivers projects its native load demand in 2017 to be 829 MW. Again, these demands can be adequately met with the 978 MW Big Rivers will have available beginning in 2012.

Under its base case forecast, Big Rivers projects steady demand growth of 10 MW to 14 MW annually for the period 2005 through 2017, with average growth of 12.2 MW a year in its forecast. In its high case forecast, the annual average projected growth is 14.9 MW. Even under its high case forecast, Big Rivers' projected peak demand will not exceed the 775 MW contractual capacity that it has available from LEM and SEPA through 2011 or the 978 MW of contractual capacity available from the same sources through 2023, the last year of its contract with LEM. *(Although Executive Order 2005-121 calls for a review of resource adequacy through 2025, Big Rivers' most recent load forecast only extends through the year 2017. It should also be noted that Big Rivers' existing SEPA contract expires in 2016 and its LEM contract expires in 2023. This statement assumes its SEPA power contract will be extended beyond 2016.)*

Big Rivers has also included a minimum level of 50 MW of firm off-system sales per year, which it will also be able to meet with its contractual capacity.

Because it purchases 100 percent of its system power requirements under purchases that are considered "financially firm," with contracts that provide for liquated damages in the event of non-performance, Big Rivers does not have a formal planning reserve margin. Finally, Big Rivers has no plans to add base load or peaking capacity in the years from 2005 through 2017. Nor does it plan to retire any generating capacity during this period.

East Kentucky Power - Resource Summary

Existing Generation/Supply Resources

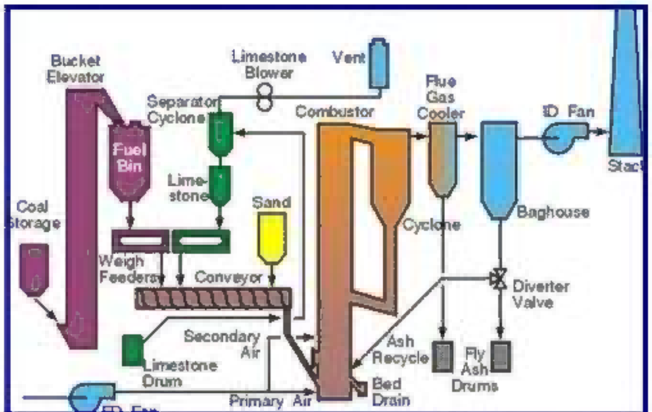
East Kentucky Power is a not-for-profit G&T utility which provides wholesale electric service to 16 member/owner distribution cooperatives in 89 counties throughout eastern and central Kentucky. Through these distribution cooperatives, it serves approximately 475,000 retail customers. In addition to its owned generation, which consists of 1,996 MW of coal-fired, base load capacity and 842 MW of natural gas-fired peaking capacity, East Kentucky Power has 170 MW of capacity available under a contract with SEPA.

Resource Planning

East Kentucky Power's planning cycle begins with its load forecast and consists of developing a capacity expansion plan and identifying potential financial impacts of implementing the plan. It develops a load forecast with input from all member systems every two years in accordance with Rural Utilities Service (RUS) requirements. It files an IRP every three years with the Commission. East Kentucky Power's evaluation of capacity needs is based on its latest load forecast, a capacity technology assessment, a screening analysis of capacity alternatives, including DSM, and a risk assessment of its expansion plan. The plan is simulated and input into East Kentucky Power's financial model to determine the impact on its margins and rates. The base plan is reviewed and reevaluated as necessary. A long-term financial forecast is developed annually which includes updated fuel costs and East Kentucky Power's base expansion plan with adjustments.

Capacity additions are generally made through a Request for Proposals (RFP) process in which East Kentucky Power exercises no control over the technologies bidders may offer. New technologies may be offered as self-build options if they are considered mature enough to be reliable. Circulating fluidized bed (CFB) boiler technology, such as the Gilbert Unit that became commercial in March 2005, is a relatively new technology for coal-fired generation. East Kentucky Power is presently planning to add at least two more coal-fired units using this same CFB technology.

Three years ago, East Kentucky Power began investigating the use of methane gas produced naturally at landfills to generate electricity. After completing an evaluation of the economics of these projects, East Kentucky Power constructed three landfill gas plants in 2003 and a fourth plant is planned for completion in late 2005. East Kentucky Power is studying methane recovery from certain industrial waste processes for electric generation. It is also studying wind as a potential renewable energy resource.



Circulating Fluidized Bed Combuster

In 2008, Warren RECC will become a member of East Kentucky Power and will receive wholesale power service. Following the issuance of an RFP and review of those proposals, East Kentucky Power applied to the Commission for a Certificate of Public Convenience and Necessity (CPCN) to construct a 278 MW CFB coal-fired unit at its Spurlock station to serve Warren RECC's load in 2008. That case is currently pending before the Commission. East Kentucky Power also has pending a second application for a CPCN to construct a 278 MW CFB coal-fired unit and five 90 MW combustion turbines at its J.K. Smith station with an in-service date of 2009. Projects identified by East Kentucky Power with in-service dates beyond 2009 are placeholders for future capacity additions. No commitments have yet been made for those projects.

East Kentucky Power's resource plan includes a significant number of gas-fired combustion turbines which are planned to meet peaking needs and some intermediate load needs. Forecasts of future fuel prices are also prepared and they are updated for use in preparing major power supply studies or the triennial IRP.

East Kentucky Power, in conjunction with its member distribution cooperatives, offers various DSM programs. The majority of these are residential. One non-jurisdictional program is non-residential interruptible rate pricing, which currently has 124 MW of interruptible demand. The DSM programs currently offered are discussed in detail in the Energy Efficiency, Demand-Side Management and Conservation section.

Resource Adequacy

East Kentucky Power's base case forecast projects a system peak demand of 2,633 MW in 2005 and a system peak demand of 5,158 MW in 2024. Its high case forecast projects peak demands of 3,028 MW and 5,861 MW in 2005 and 2024, respectively. Unlike many of the other major utilities in Kentucky, East Kentucky Power's system peak consistently occurs during the winter, rather than the summer.

East Kentucky Power uses a 12 percent target reserve margin, which, from a planning perspective, it meets during the summer with its owned generation and SEPA power purchases. However, it purchases blocks of firm power during the winter months to meet its reserve margin.

Kentucky Power - Resource Summary

Existing Generation/Supply Resources

Kentucky Power, a subsidiary of American Electric Power Company, Inc. (AEP), a multi-state public utility holding company, serves approximately 175,000 customers in 20 counties in eastern Kentucky. Of its total available capacity of 1,450 MW, Kentucky Power owns 1,060 MW of coal-fired generation, and purchases the other 390 MW from an AEP affiliate under two unit power agreements. These unit power agreements, under which Kentucky Power purchases power from the Rockport Generating Station in southern Indiana, run through December 7, 2022.

AEP has nine subsidiaries that are operating utilities that provide electric service in 11 Midwest and South-Central states through the AEP-East and AEP-West power pools. Kentucky Power, along with four other AEP subsidiaries, is a member of the AEP-East power pool, and collectively they serve customers in seven states.

Resource Planning

Planning for Kentucky Power is performed by AEP, which conducts resource planning for the AEP-East power pool on a system-wide basis. AEP forecasts future customer demands and energy requirements, including committed sales to unaffiliated systems, and establishes a "target" which the system's resources must be able to serve with adequate reliability. It applies reliability or reserve criteria and determines how much reserve capacity is required to meet the requirements with a specified level of reliability. The result of this process is reduced to an equivalent reserve percentage based on more detailed analyses.

AEP reviews the adequacy of current and planned resources to meet the system's needs. This involves making a projection of the system's current and committed resources, taking into account anticipated capacity additions and retirements and currently scheduled purchases. This is then compared with its projected load requirements, taking into account reserve requirements to determine the need for additional resources. Any projected capacity deficiencies identified in this process indicate a need for additional resources. The pattern of such needs over time establishes the outline of required resource additions.

AEP reviews available future resource options including different types of supply-side resources such as new generation, generating unit ownership arrangements, power purchases, special opportunities, etc., as well as demand-side resources. AEP catalogs the various engineering, operational, and cost characteristics of each resource as part of determining the mix of resources that produces a low cost, reliable resource plan. AEP compares the total costs of owning and operating the system assuming different mixes of resource options, keeping in mind that flexibility in a capacity resource plan is a major advantage.

AEP monitors and revises all steps of the planning process on an ongoing basis, as appropriate. Updated estimates become available from time to time and are taken into account as practicable. Implementing the plan involves implementing feasibility analyses which may include additional analyses regarding the plan's financing requirements, specific ownership arrangements, etc. Once the plan is finalized, acquisition of the selected resources is arranged.

AEP is evaluating a mix of generation resources to meet the AEP-East power pool's projected capacity needs through 2015. AEP projects it may need additional capacity resources by 2006. Until then, capacity needs will probably be met through purchases from the market on an as-needed basis. Prior to 2015, AEP also expects to construct and/or acquire generation facilities in the AEP-East power pool, but the precise timing, technology mix, location, and size of such additions remain under review.

(AEP has researched and continues to evaluate integrated coal gasification combined cycle (CSS) technology. AEP is still considering whether to site an IGCC unit in Kentucky, Indiana or Ohio.)

DSM planning is generally performed at the same time as capacity resource planning but is performed on a utility specific basis. The evaluation process for DSM begins by establishing a DSM measure database, performing preliminary screening, and then analyzing the cost-benefit of the DSM measure. The DSM measures that pass the cost-benefit test are combined with supply-side models and the participant cost-benefit is analyzed. Finally, the DSM measures that pass those tests will be implemented with a follow-up review to verify performance.

Kentucky Power administers a formally approved DSM program under which it recovers costs via a DSM surcharge. Kentucky Power's DSM budget for 2005 is $678,250.

(DSM programs and DSM surcharges are discussed in detail in the Energy Efficiency, Demand-Side Management and Conservation section.)

Resource Adequacy

Kentucky Power's projected load and capacity, and the projections of load and capacity for the other members of the AEP-East power pool, indicate that Kentucky Power's obligation for additional capacity could be up to 500 MW by 2015. Kentucky Power's base case and high case demand forecasts include projected peak demands in excess of its available capacity in every year from 2005 through 2024. In the early years of this forecast period, Kentucky Power expects to meet its peak demand requirements with purchases of capacity from other members of the AEP-East power pool and occasional purchases in the wholesale market as it has done in recent years. However, Kentucky Power needs to purchase capacity for relatively few hours during the year.

The AEP-East power pool is now a member of PJM Interconnection (PJM), a regional transmission organization which has operational control of the AEP-East power pool's transmission system, and, therefore, Kentucky Power's transmission system. The AEP-East power pool is required to comply with PJM's reserve margin requirements. PJM has set the Installed Reserve Margin for the June 2005 through May 2006 planning period at 15.0 percent. Using current AEP reliability and diversity factors, this translates into an Installed Reserve Margin for AEP of 14.07 percent. This compares with a 12 percent margin that AEP used, based on its own determinations, from the late 1990s until joining PJM.

AEP has not established a fixed reserve margin for Kentucky Power. Kentucky Power is expected to provide its share of the AEP-East power pool's capacity on a proportionate basis, as opportunities arise. Within the next several years, Kentucky Power and AEP expect that new generation will be added by one or more members of the AEP-East power pool and that Kentucky Power will share in the ownership and cost responsibility, to some extent, of this new generation. Kentucky Power has no plans to retire any of its existing generating capacity, but may experience reductions in existing capacity if additional emission controls are required.

KU and LG&E - Resource Summary

Existing Generation/Supply Resources

KU provides electric service to approximately 485,000 customers in 77 counties throughout central, southeastern and western Kentucky. LG&E is a combination gas and electric utility serving approximately 389,000 customers in the greater Louisville - Jefferson County area and eight surrounding counties. KU and LG&E merged in 1998 but have retained their separate corporate identities. They are both subsidiaries of LG&E Energy LLC., a registered public utility holding company. While each utility owns its own generation, it is all jointly dispatched. All generation planning is also performed on a joint basis. In addition to their owned generation, KU and LG&E, through long-term contracts, have access to 200 MW of generating capacity from Electric Energy Inc. (EEI), 179 MW from Ohio Valley Electric Corporation (OVEC), and 195 MW from Owensboro Municipal Utility (OMU).

In addition to existing generation, KU and LG&E have jointly proposed to construct a 732 MW (summer rating) super-critical pulverized coal-fired base load generating unit at LG&E's Trimble County station (Trimble County No. 2). KU and LG&E will own 75 percent, or 549 MW, of the new unit. The Illinois Municipal Electric Agency (IMEA) and the Indiana Municipal Power Agency (IMPA), which own 25 percent of the Trimble County No. 1 coal-fired unit, intend to own 25 percent of Trimble County No. 2. Applications relating to the construction of Trimble County No. 2 are currently pending before the Commission and the Kentucky State Board on Electric Generation and Transmission Siting (Siting Board).

Resource Planning

KU and LG&E review planning alternatives and decisions annually as part of an ongoing resource planning process. Detailed resource planning is performed every three years as part of their joint IRP process. Demand and energy forecasts are prepared annually. In this integrated resource planning process, the economics and practicality of supply-side and demand-side options are examined to determine cost-effective responses to customers' needs. The steps undertaken in this process are: (1) establishment of a reserve margin criterion; (2) assessment of the adequacy of existing generating units and purchase power agreements; (3) assessment of potential purchased power market agreements; (4) assessment of demand-side options; (5) assessment of supply-side options; and (6) development of an economic plan from the available resource options. Screening of DSM options is also performed as part of this joint IRP process.

KU and LG&E have individually approved DSM programs with applicable DSM surcharges. A summary of the major existing DSM programs is included in the Energy Efficiency, Demand-Side Management and Conservation section. The DSM budget for each company through 2007 is as follows:

	2005	2006	2007
KU	$4,519,843	$4,642,473	$4,586,962
LG&E	$5,080,519	$5,223,187	$5,188,434

Resource Adequacy

KU's and LG&E's base case forecast projects a combined peak demand of 6,696 MW in 2005, growing to 8,794 MW by 2019. In their high case forecast, they project a combined peak demand of 6,748 MW in 2005 growing to 9,402 MW by 2019. In order to meet the growth projected in their base case forecast and maintain an adequate reserve margin, they plan to add approximately 2,100 MW of coal-fired base load capacity, 900 MW of natural gas-fired peaking capacity, and 180 MW of hydro capacity over the next 20 years.

The combined companies established an optimal reserve margin range in 2002 of 13 percent to 15 percent, with 14 percent recommended for planning purposes. The reserve margin analysis included in the KU and LG&E 2005 IRP recommends a range of 12 percent to 14 percent, while maintaining a 14 percent reserve margin for planning purposes.

KU and LG&E have no current plans to retire any existing generating units during the 2005 and 2025 period. However, KU and LG&E stated that some retirements are likely in the future due to the age of some units and the expected economics associated with future environmental compliance. KU and LG&E have over 1,300 MW of generation that is 35 years old or older.

ULH&P - Resource Summary

Existing Generation/Supply Resources

ULH&P, a wholly-owned subsidiary of the Cincinnati Gas & Electric Company (CG&E), is a combination gas and electric utility serving approximately 122,000 customers in five counties in northern Kentucky. CG&E is a wholly-owned subsidiary of Cinergy Corporation, a registered public utility holding company. ULH&P currently owns no generation. It has historically relied on CG&E to provide 100 percent of its power requirements via wholesale purchased power contracts. The current wholesale power contract expires at the end of 2006.

In response to the concerns expressed by the Commission in Administrative Case No. 387 regarding ULH&P's exposure to market- based prices for electricity, ULH&P proposed to acquire 1,105 MW of generating capacity from CG&E. The Commission initially approved the acquisition of the generating facilities on December 5, 2003 in Case No. 2003-00252. The transaction has received all other required approvals, except that of the Securities and Exchange Commission (SEC).

The transaction approved by the Commission also allows ULH&P to take power from CG&E when ULH&P's generation is not available; however, ULH&P will solicit bids for its back-up power supply needs and other parties will have an opportunity to beat the bid price offered by CG&E.

Resource Planning

Development of ULH&P's IRP involves two major processes, one organizational and one analytical. The organizational process involves the formation of an IRP team with representatives from key functional areas of Cinergy. The analytical process involves these steps: (1) develop planning objectives, assumptions and a load forecast; (2) screen potential demand-side resource options; (3) screen, and perform sensitivity analysis of the cost-effectiveness of potential supply-side resource options; (4) screen, and perform sensitivity analysis of the cost-effectiveness of potential environmental compliance options; (5) integrate the demand-side, supply-side and environmental compliance options; (6) perform final sensitivity analyses on the resource alternatives and select the plan; and (7) determine the best way to implement the chosen plan.

ULH&P's resource planning considers both demand-side and supply-side resources. On the demand-side, it intends to implement all cost-effective DSM programs, subject to the receipt of all necessary approvals. DSM programs are initially identified through a market potential analysis conducted by external consultants. All measures and programs so identified are evaluated for cost-effectiveness. As noted above, the load impacts of the recommended DSM programs are also included as a component in ULH&P's IRP.

ULH&P has a formally approved DSM program with an applicable DSM surcharge. ULH&P periodically files with the Commission for approval of new DSM programs or for the extension of existing DSM programs. A brief description of the DSM programs currently offered by ULH&P is included in the Energy Efficiency, Demand-Side Management and Conservation section. The annual budget for ULH&P's DSM programs is about $2.5 million.

New technologies are considered in Cinergy's generation planning processes. Subcritical and supercritical pulverized coal units, fluidized bed units, advanced CTs and combined cycle units, fuel cells, wind turbines, solar, biomass, and storage units are all considered. None of these new technologies have been implemented on a large scale commercial basis. Cinergy is currently involved in a detailed study with GE and Bechtel concerning the potential construction of an integrated gasification combined cycle (IGCC) unit.

Resource Adequacy

ULH&P's base case load forecast projects peak demands of 914 MW in 2005 and 1,116 MW in 2025, respectively. Its high case forecast projects a peak demand of 917 MW in 2005 and 1,178 MW in 2025. ULH&P will be using a target reserve margin based on several components which have historically been used by CG&E. The components include: (1) operating reserve of 4 percent; (2) unscheduled outages - the greater of 8 percent or the loss of the largest generating unit; and (3) weather-induced load forecast uncertainty identified as 3 percent. Upon the acquisition of its new generation, ULH&P will have a target reserve margin of 16.2 percent, which will gradually decrease to a 15 percent level by 2020 as its load grows.

With a planning reserve margin of 15 to 16 percent, ULH&P projects that it will have no need for additional capacity until 2013. Since the first capacity addition after 2005 is not expected until 2013, and since it has no plans for the retirement of East Bend 2, Miami Fort 6, or Woodsdale 1-6, ULH&P indicates that its long-term capacity needs will continue to be reassessed on a going forward basis.

Purchases from the wholesale market may be used to meet its reserve margin criteria during peak demand times in years prior to when it adds additional capacity.

Non-Jurisdictional Electric Utilities Resource Summary

(Not all non-jurisdictional systems provided information in this proceeding. The Commission has attempted to verify all information.)

Electric service is also supplied to parts of Kentucky by 30 municipal electric systems, TVA, and five TVA supplied distribution cooperatives. None of these suppliers are regulated by the Commission. Two of the municipal systems, Henderson Municipal Power and Light (HMP&L) and Owensboro Municipal Utilities (OMU), own their own generating facilities.

(The city of Paris owns 7 diesel generating units with a total capacity of 12 MW used for peaking purposes. Its supplier, KU, can call upon the use of this generation for up to 200 hours per year.)

HMP&L's generation is operated and managed by WKE, a non-regulated affiliate of LG&E, pursuant to a lease agreement with Big Rivers. OMU operates its own facilities but the power in excess of OMU's needs is provided to KU and LG&E pursuant to a power purchase agreement. The rest of the municipal systems purchase power from TVA, KU, Kentucky Power or CG&E.

The 13 municipal systems supplied by TVA are typically served under indefinite term full-requirements contracts that can be terminated by either party upon five years' notice. According to the information provided in this proceeding, two systems, Glasgow and Princeton have given such notice. Paducah's contract expires in 2009. The 12 municipal systems supplied by KU have full-requirements contracts with five-year cancellation notices, with the exception of Berea whose contract has a three-year cancellation notice. The two systems supplied by Kentucky Power have contracts continuing through the end of 2005. One system is supplied by CG&E.

Warren RECC gave its five-year notice to TVA in 2003. In 2008, it plans to become a member of East Kentucky Power.

The 28 municipal systems that purchase all or some of their generation and the RECCs that purchase their power from TVA are shown in the chart on the following page.

Resource Planning

Resource planning for a large majority of the non-jurisdictional electric systems is performed by their wholesale power suppliers. However, some systems perform their own planning function. In addition, some systems utilize the service of an external consulting firm to perform their planning.

Resource Adequacy

As noted previously, Kentucky's non-jurisdictional electric utilities tend to be primarily distribution systems served by either TVA, with no independent regulatory oversight, or by KU, Kentucky Power or CG&E pursuant to wholesale power agreements under the Federal Energy Regulatory Commission's (FERC) jurisdiction. As their non-jurisdictional status would imply, the Commission maintains little information on these utilities on a regular basis. However, the information provided in this proceeding indicates that these utilities, in conjunction with their wholesale power suppliers, have made and are making provisions for supplying their customers in the future. It should also be noted that, historically, KU and Kentucky Power have included the supply of wholesale power to the municipal systems they serve as part of their IRP filings with the Commission.

TVA supplied municipal systems

Benton Electric System
Glasgow Electric Plant Board
Fulton Electric System
Jellico Electric & Water System
Monticello Electric Plant Board
Paducah Power System
Russellville Electric Plant Board
Bowling Green Municipal Utilities
Franklin Electric Plant Board
Hopkinsville Electric System
Mayfield Electric & Water System
Murray Electric System
Princeton Electric Plant Board

KU supplied municipal systems

Barbourville Utility Commission
Bardwell
Berea Municipal Utilities
Falmouth
Madisonville Municipal Utilities
Paris
Bardstown Municipal Utilities
Benham
Corbin Utilities Commission
Frankfort Electric and Water Plant Board
Nicholasville City Utilities
Providence

Kentucky Power supplied municipal systems

Electric Plant Board of the City of Vanceburg
Olive Hill Electric Company

Cinergy supplied municipal system

Williamstown Utility Company

TVA supplied electric cooperatives

Hickman-Fulton Counties Rural Electric Cooperative Corporation
Pennyrile Electric
Tri-County
Warren RECC
West Kentucky Rural Electric Cooperative Corporation

Merchant Plants

For the purpose of this report, merchant plants are defined as those electric generating facilities that are privately owned, sell the energy they produce into the wholesale market, and whose rates are not regulated by the Public Service Commission. WKE and Dynegy are currently the only operators of merchant plants in Kentucky. Together, they have a combined capacity of 3,218 MW at nine different sites. This represents about 23 percent of Kentucky's electric generation capacity.

WKE

The generation that WKE operates was built and is owned by Big Rivers. As previously noted, WKE operates this generation under a lease agreement with Big Rivers that runs through 2022. WKE is an affiliate of LG&E. Another LG&E affiliate, LEM, currently is obligated to sell 597 MW to Big Rivers and that obligation will increase to 800 MW in 2012. A table showing the Big Rivers' generation leased to WKE follows.

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Reid	Webster	one	65	coal	1966
Coleman	Hancock	three	455	coal	1969-1972
HMP&L Station 2	Webster	two	405	coal	1973-1974
Reid CT	Webster	one	65	fuel oil	1976
Green	Webster	two	454	coal	1979-1981
Wilson	Ohio	one	420	coal	1986

Dynegy

Dynegy owns the only merchant plants that were originally constructed for the primary purpose of selling power to the wholesale market. Dynegy owns eight natural gas fired turbines at 3 generation stations. Their combined capacity is 1,774 MW. The Dynegy generators were constructed in 2001 and 2002, when natural gas prices ranged around $3 to $4 per Mcf. Gas prices now are consistently over $6 per Mcf and are not forecast to decline in the foreseeable future. As we learned in Administrative Case No. 387, Dynegy's Bluegrass station has not operated in recent years. Dynegy's Foothills and Riverside generation has been operated only when gas prices made it economical to do so. A table showing the Dynegy generation located in Kentucky follows:

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Dynegy – Riverside	Lawrence	three	690	gas	2001
Dynegy – Foothills	Lawrence	two	460	gas	2002
Dynegy – Bluegrass	Oldham	three	624	gas	2002

Cogeneration

In addition to the merchant plants shown above, other non-utility generation in Kentucky operates as cogeneration facilities, meaning, generally, that it is industry-owned and operated by an entity whose primary business is not electric generation. A cogeneration facility typically uses an industrial waste product to generate electricity for use in the industry's manufacturing process. This electricity displaces the electricity that the cogenerator would otherwise purchase from the incumbent utility. If the cogenerator produces more electricity than is necessary to meet its needs, the excess is purchased by the utility at the utility's avoided cost. A table showing the cogenerating units located in Kentucky follows:

Generating Station	County	Units	MW	Fuel	Initial Operation
Cinergy – Silver Grove	Campbell	one	20	gas	2001
Weyerhauser – Ky. Mills	Hancock	one	88	wood waste	2001
Cox – Waste to Energy	Taylor	one	4	wood waste	1995
Air Products - Calvert City	Marshall	one	27	gas	2000

Kentucky Board on Electric Generation and Transmission Siting

In 2002 the General Assembly enacted legislation creating the Siting Board. The legislation requires that a merchant plant obtain a CPCN from the Siting Board prior to its construction. Since its inception, the Siting Board has received five applications to construct merchant generating facilities, all of which have been for base load generators. Four of the proposed merchant plants proposed utilizing coal; the other proposed using a mixture of coal and Refuse Derived Fuel as the major fuel source. Four of the applicants were granted conditional approval; one is pending with the Siting Board. The proposed merchant plants that have given notice to the Commission are shown below:

Company	Case No.	Date of Final Order	Results
Kentucky Mountain Power	2002-00149	9/5/2002	Conditional certificate
Thoroughbred Generating Co.	2002-00150	12/5/2003	Conditional certificate
Westlake Energy Corp.	2002-00171	4/14/2005	Withdrawn
Estill County Energy Partners	2002-00172	10/12/2004	Conditional certificate
Kentucky Pioneer Energy	2002-00312	11/10/2003	Conditional certificate
DTE Wickliffe	2005-00108	4/13/2005	Withdrawn
IMEA & IMPA	2005-00152	Pending	Pending

The Illinois Municipal Electric Agency and Indiana Municipal Power Agency filed Case No. 2005-00152 requesting a construction certificate for their purchase of 25 percent of KU's and LG&E's 732 MW Trimble County Unit 2. The remaining 75 percent of the unit will be non-merchant and jurisdictional.

In its comments, Kentucky Pioneer Energy (Kentucky Pioneer) expressed several concerns relating to the new Siting Board legislation that it found as barriers to investment. The two most significant related to the application of the legislation and the lack of a level playing field between merchant plants and regulated utilities.

<u>Merchant Plant Economics</u>

Generally, the decision to build a merchant generator in today's post-Enron financial climate entails significant risk. Because merchant generators operate competitively, in a cost minimizing environment, and have no guarantee of cost recovery as a cost-of-service regulated utility does, and because construction of a generator is very capital intensive, they often have difficulty obtaining financing.

To be viable merchant generators must exploit their market advantages and may do so in a number of ways. In order to minimize costs, some merchant plants are sited in a location as to minimize fuel cost, either near a natural gas pipeline or near a coal supply. Some plants use a fuel source that is less expensive or whose use is subsidized, such as waste coal, or municipal waste. Other plants may locate their generation close to a load where transmission constraints diminish the ability for bulk power imports to that load, thus giving themselves a market advantage in that area.

In addition to minimizing cost, it is also necessary to minimize uncertainty, especially in order to acquire financing. Some merchant plants enter into long-term contracts to supply needed base load capacity to an end-user, such as a regulated electric utility, a municipality, or even an industrial park or electricity intensive end-user (in states that have restructured). The low cost rates of Kentucky's electric utilities add an additional barrier to obtaining financing because of the difficulty that merchant plants have in obtaining Kentucky's regulated utilities as customers since they must compete with the regulated utilities self-construct alternatives.

Finally, merchant generators may also seek to enter agreements with regional market operators to commit all or some of their resources to that regional market as the operator seeks to increase regional reliability. How this installed capacity is to be compensated is being debated by regional market operators including both PJM and the Midwest Independent System Operator, Inc. (MISO).

In Kentucky, the merchant plant proposals have fit the scenarios mentioned above. Plants have been proposed near a fuel supply, with peaking units near the natural gas pipelines, and coal-fired units near the "mine-mouth" or on abandoned mine sites thus ensuring an adequate coal supply while minimizing transportation cost of that coal. Proposed plants have also sought fuel supplies that were less expensive or subsidized, such as waste coal, or municipal solid waste. One element of the above scenarios that, to the knowledge of the Commission, has not been developed for merchant plants in Kentucky is the acquisition of long-term power supply contracts. That may be a contributing factor to the lack of merchant plant construction within the Commonwealth.

Merchant Power Sales to Regulated Utilities

Merchant plants may offer utilities a viable alternative to adding new regulated generation.

In response to the Commission's data requests, all six jurisdictional generating utilities indicated some reliance on short-term and long-term purchased power from the wholesale power market in which most merchant plants compete. In describing their resource development or acquisition processes, the jurisdictional generating utilities noted that they routinely request and evaluate competitive power supply offers in addition to evaluating the cost to self-construct. Kentucky's regulated utilities consider power supply bids submitted by merchant plants as part of their resource mix. However, as was found in Administrative Case No. 387, there is little evidence to suggest that merchant power at market prices will be below the cost-of-service rates of Kentucky's current electric customers.

Benefits of Merchant Plants

Peabody Energy advocates considering the economic benefits of electricity sales from merchant plants to other states, noting that 75 percent of the coal produced in Kentucky is used outside the state but also acknowledges that merchant plants face barriers to market entry. Peabody Energy urges Kentucky to address barriers to the financing and construction of merchant plants in the

state.

Peabody states that greater use of Kentucky coal to generate electricity would be beneficial to the coal industry. Merchant plants that generate electricity with Kentucky coal could benefit the state economically, regardless of where their output is sold. Peabody states that electricity should be viewed as any other Kentucky made product. However, as noted by Big Rivers, merchant plant generation of electricity will use a portion of the emissions allowances allocated to Kentucky, which could have negative consequences for regulated utilities and their customers,

Kentucky's future energy policy must strive to strike a balance between becoming a large scale energy exporter and protecting our status as having the lowest cost electricity in the nation.

Conclusions

Kentucky's future energy policy must strive to strike a balance between becoming a large scale energy exporter and protecting our status as having the lowest cost electricity in the nation. This is a difficult task with many factors to address that may have a significant impact on the electric utilities operating in Kentucky and our ability to attract merchant plants.

As Kentucky's current generating plants age or new environmental requirements are imposed, merchant generation may become feasible and attractive to our regulated electric utilities. And, considering that merchant plants that utilize Kentucky coal or coal waste can provide economic benefits beyond the generation of electricity, the need to balance the merchant issue becomes more important.

Another area which was addressed by recommendations in the *Comprehensive Energy Strategy* was clean coal technology. This may be an area where utilities, the merchant industry and the research community to form partnerships to help Kentucky become both a leader in this alternative technology and become a large scale energy exporter. The Comprehensive Energy Bill just passed by Congress authorizes the establishment of significant federal programs devoted to clean coal technology and provides additional incentives in the form of loan guarantees and investment tax credits. Kentucky must actively and aggressively pursue these funds if it wants to promote the development of clean coal technologies.

Resource Adequacy - Transmission

Electric Transmission Status

The electric transmission system in Kentucky serves two primary purposes. One is to enable electric utilities to provide adequate, reliable electricity to their consumers in Kentucky; the other is to accommodate economic bulk, wholesale power transfers. Those transfers can be entirely within Kentucky, exported from Kentucky, imported into Kentucky, or transferred through Kentucky. Each transmission provider defines "transmission" slightly differently, but they all generally consider transmission facilities to be those operating at 69 kV or higher, while distribution facilities are those operating below 69 kV. The Kentucky transmission system has demonstrated the ability to deliver power to Kentucky customers reliably. However, it is generally known that the system is limited in the amount of power it can transfer through the state, particularly north and south. New transmission projects will undoubtedly be responsive to meet Kentucky's future electricity needs. Similarly, new transmission may be required to ensure that Kentucky ratepayers benefit, and any negative effects are mitigated, from continued development of regional electricity markets.

Kentucky's electric transmission system is actually seven individual systems that are interconnected at numerous points throughout the state. These seven transmission systems are owned by five utilities regulated by the Commission, the TVA and CG&E.

(CG&E owns the transmission facilities located in northern Kentucky that are used to provide bulk power at wholesale to ULH&P.)

Transmission Miles by Voltage for Each Utility

Voltage	Kentucky Power	Big Rivers	CG&E	East Kentucky Power	KU and LG&E	TVA
69	417	791	126	1,864	2,581	4 32
138	299	15	104	388	1,172	
161	46	341		333	55	1,008
345	9	68	61	60	482	
500					36	85
765	258					
Total Miles:	**1,029**	**1,215**	**291**	**2,645**	**4,930**	**1,525**

Numbers derived from the Public Service Commission's GIS database for Electric Transmission collected in 2001-2004.

Each of these systems was created to transfer power from its own generators to its own customers. Over time the systems became increasingly interconnected for mutual reliability benefits, load diversity, and to reduce the occurrence of redundant facilities. Since the individual transmission systems operate at different voltages, interconnection usually requires the construction of expensive transformers (substations) at each interconnection point. FERC generally regulates the transmission system with the state commissions having some limited authority.

Adequacy to Serve its Kentucky Customers

Each transmission provider in Kentucky has a history of providing adequate transmission service to its customers and has planning tools in place to ensure adequate system expansion and service in the future. Each uses reliability indices to measure system performance. All use System Average Interruption Duration Index (SAIDI) to measure the duration of service interruptions and another index to measure the frequency of interruptions.

The transmission providers also follow National Electric Reliability Council (NERC) transmission guidelines and those of their respective Regional Reliability councils. These guidelines, though currently voluntary, specify continual evaluation of the system's ability to deliver anticipated power demands even if one critical element of the system is out of service. The guidelines also outline the need for study of more severe scenarios such as having multiple facilities out of service at the same time. The guidelines specify that the system be designed and capable of operating within its rated capacities with one critical element out of service and that

the system can be controlled if multiple elements are out of service. The recently enacted federal energy bill directs FERC to ensure the establishment of mandatory reliability standards, which will presumably be based on the NERC model.

Adequacy to Serve Bulk, Wholesale Transfers

The growth of the competitive wholesale market for electricity has placed increasing demands on the transmission system which was built primarily to facilitate intrastate transfers from generation to distribution. Bulk wholesale power transfers require strong interconnections between adjacent transmission systems. Peabody Energy points out that power transfers from north of Kentucky to south of Kentucky, and vice versa, are limited by the lack of interconnection between Kentucky's regulated utilities and TVA. Administrative Case No. 387 found the same limitations to north-south flows, as have transmission planning studies conducted by MISO.

These limitations restrict the ability of Kentucky's utilities to export excess capacity and benefit from off-system sales. The congestion on the bulk transmission system, at times, limits the ability of Kentucky's regulated utilities to serve their customers from their lowest cost generation raising their generation costs.

Constructing facilities to improve these interconnections and relieve constraints would allow more economic wholesale transfers to occur and may make it more feasible for independent power producers to locate in Kentucky. There is much debate within RTOs and at FERC concerning how to determine the beneficiaries of such improvements and who should bear the cost of construction. Some of the additional transmission interconnections that have been discussed may not be necessary for Kentucky's regulated utilities to meet their obligations to reliably and economically serve their customers. While many of the transmission constraints impacting Kentucky are primarily the result of the wholesale electricity market, it is unclear the extent to which transmission upgrades would enable some Kentuckians to benefit from lower cost power or other Kentuckians to benefit from increased sales by their utility.

Vulnerability to Cascading Outages

The record of this case includes a January 24, 2005 report prepared for the Commission by Commonwealth Associates, Inc. (CAI) entitled *Assessment of Kentucky's Transmission System Vulnerability to Electrical Disturbance.* The study focused on the design of Kentucky's transmission system and assumed that the system is maintained adequately. The report discusses the results of an evaluation of how vulnerable the electric transmission system in and around Kentucky is to cascading outages similar to those experienced in the northeast and upper Midwest on August 14, 2003.

(On August 14, 2003, the Northeastern U.S. and portions of Ontario, Canada experienced power blackouts initiated by high voltage transmission line failure in northern Ohio. See *U.S. - Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004.)

CAI's central conclusion was that there were certain possible circumstances where the loss of multiple transmission facilities could result in widespread outages. CAI went on to say that,

[I]t may be that detailed review by the utilities or others will show that the possibility can be precluded. It would not be unusual to expect that detailed studies by the utilities that have more intimate knowledge of their systems, along with more detailed models, would result in the elimination of many, if not all, of the base case scenarios. Alternately if scenarios cannot be eliminated, then mitigation measures such as changes to system protection, system operating procedures, or new facilities would be investigated. If adopted, these changes might eliminate the reasonable possibility of widespread outages.

(Assessment of Kentucky's Transmission System Vulnerability to Electrical Disturbances. (January 24, 2005, at 3).)

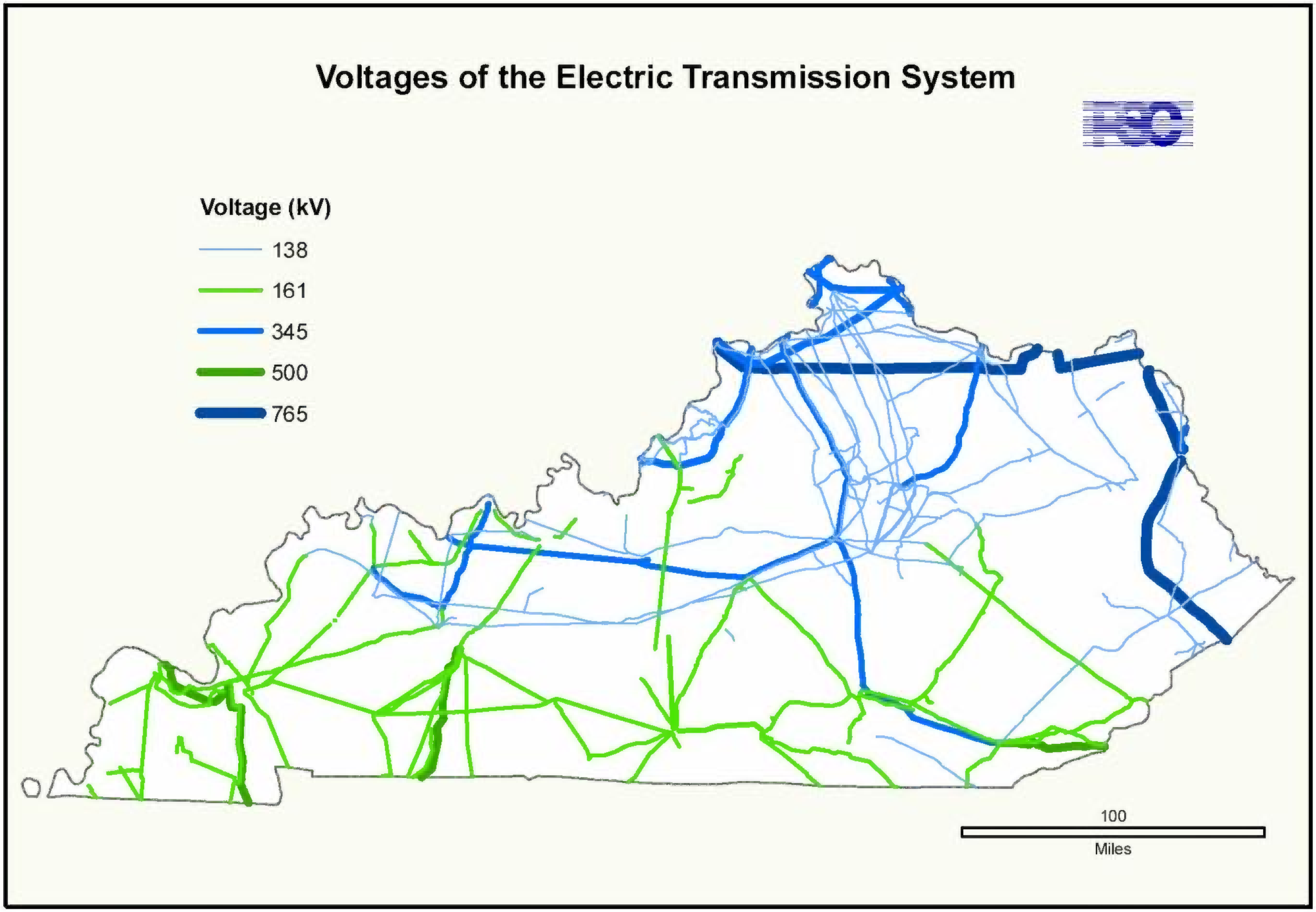
Each jurisdictional high voltage transmission owner has certified to the Commission that it has addressed each of the scenarios identified as potential problems in the CAI study to minimize the risk of widespread outage from them. TVA is not jurisdictional to the Commission but its transmission planners do have the CAI results for consideration.

A map of Kentucky's high-voltage transmission system follows on the next page.

CAI also noted that since Kentucky has generating sources that meet or exceed the load within the state, it is reasonable to infer that Kentucky is less vulnerable to widespread outages than areas that must import power to meet load. CAI stated that the study "results imply that the grid is more than twice as vulnerable to widespread outages during a large transfer across Kentucky than it is under base or 'normal' conditions."

CAI concluded that the Kentucky transmission system was not designed to handle the level of interstate power transfers now being experienced which are in the magnitude of 6,000 MW.

Since Kentucky has generating sources that meet or exceed the load within the state, it is reasonable to infer that Kentucky is less vulnerable to widespread outages than areas that must import power to meet load.


Voltages of the Electric Transmission System
Voltage (kV)
138
161
345
500
765
100
Miles

Maintenance and Vegetation Management

For the transmission system to provide reliable service, it must be maintained properly. Each of the jurisdictional transmission providers has a schedule for inspecting its transmission system, and each has a schedule for clearing vegetation within its transmission right-of-way (ROW). These schedules are as follow (Based on staff analysis of the responses to Staff's First Data Request, dated March 10, 2005, Item 32.):

Company	Aerial Inspection	Ground Inspection	Vegetation Control
Big Rivers	6 per year	5 year cycle	4 year cycle
East Kentucky Power	3 per year	4 year cycle	5 year cycle
Kentucky Power	2 per year	10 year cycle	Based on need
KU and LG&E	4 per year	10 year cycle	5 year cycle

The utilities use both herbicides and mechanical means to control vegetation growth within the ROW. The transmission ROW clearing and inspection costs for 2002 through 2004 are as follows (source as above):

Company	2002	2003	2004
Big Rivers	$ 511,300	$ 512,200	$ 507,400
East Kentucky Power	2,033,896	1,770,825	1,651,626
Kentucky Power	1,347,870	1,333,051	1,372,518
KU	2,891,521	3,340,527	2,453,400
LG&E	470,516	455,750	308,272

Big Rivers provided budget information. The information provided by the other utilities is actual cost.

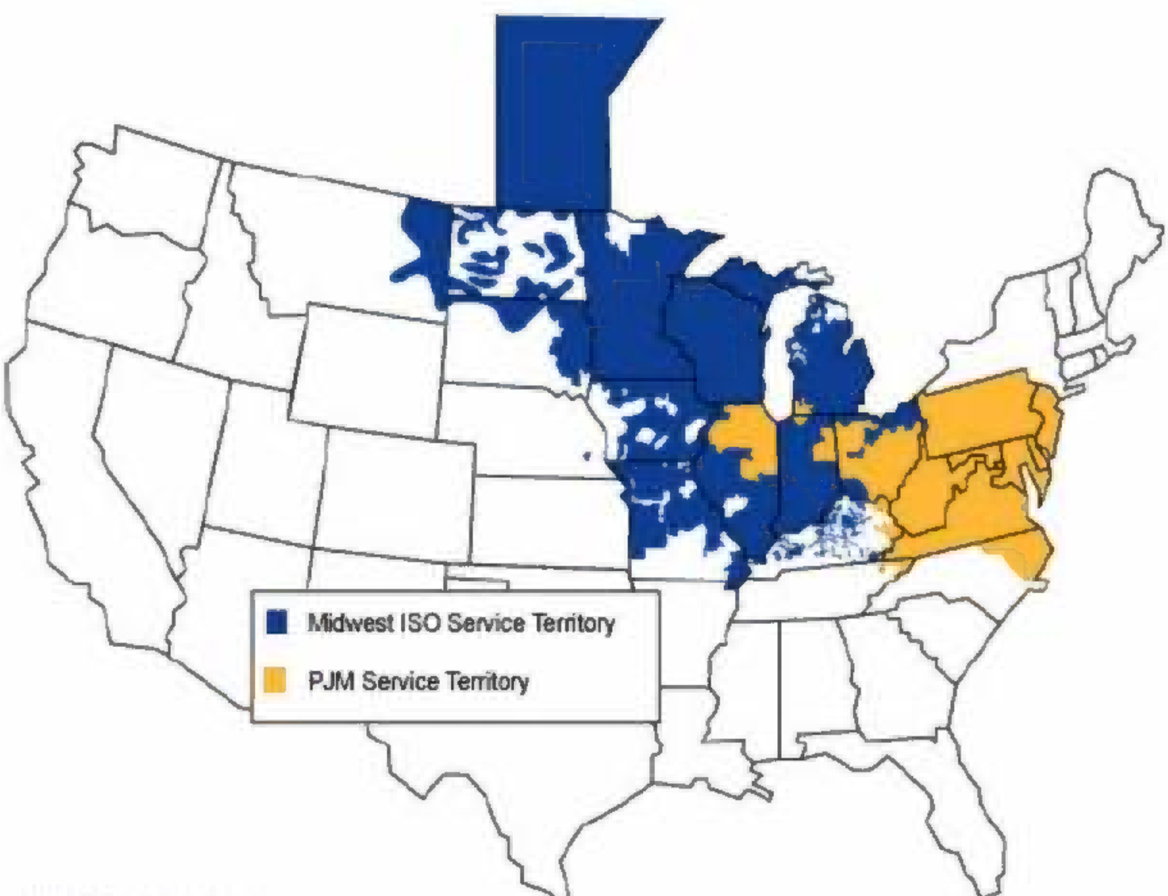
Regional Transmission Organizations

Four Kentucky electric utilities are currently members of RTOs. LG&E, KU and ULH&P (as an affiliate of Cinergy) are members of MISO, and Kentucky Power is a member of PJM. The continued membership of KU and LG&E in MISO is the subject of a case currently pending before the Commission. *(Case No. 2003-00266, Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.)*

Big Rivers and East Kentucky Power are not members of an RTO but utilize TVA to coordinate their transmission systems, pursuant to NERC operating rules.

The MISO operated transmission system spans 15 states and 1.2 million square miles. MISO is required by its charter to assess infrastructure needs on a regional basis and, in order to ensure reliability of the regional system, may suggest state-based solutions or alternatives that may build upon initiatives being undertaken in other states within the Midwest.

Midwest ISO and PJM Interconnection Inc.
National Service Areas



SOURCE: MISO

In addition, MISO identifies transmission expansion that is critical to support the competitive supply of electric power across the system.

PJM serves as the FERC approved RTO in a 13 state region that includes parts of eastern Kentucky. One of the recent initiatives under exploration at PJM is "Project Mountaineer," an initiative to utilize a regional transmission planning process to explore ways to further develop an efficient transmission "super-highway" to bring low cost coal resources to market. At this point, it should not be considered a proposal for any specific transmission line but a commitment to utilize a Regional Transmission Expansion Planning process involving various states including Kentucky, the FERC, and the transmission owners.

This project seeks to explore new transmission opportunities to improve reliability and to enhance markets for low cost energy resources. PJM states that enhancing the transmission system in this manner will bolster economic development throughout Kentucky and in the other states, prompted by a resurgence in coal resource development and utilization. This key initiative must be diligently explored by Kentucky prior to any implementation. An issue to consider is whether the resulting economic benefits will outweigh the increased transmission costs and environmental concerns associated with providing power beyond what is required to serve Kentucky's native load customers.

Siting of Transmission Lines

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

Kentucky's jurisdictional utilities that operate under the jurisdiction of the Commission must obtain Commission approval before they construct any major transmission facilities. A 2004 amendment to KRS 278.020 gave the Commission authorization to regulate the construction of transmission lines that will operate at 138 kV or higher and that are longer than 5,280 feet. KRS 278.020 does not directly address siting issues for transmission facilities but addresses the need of the proposed facility.

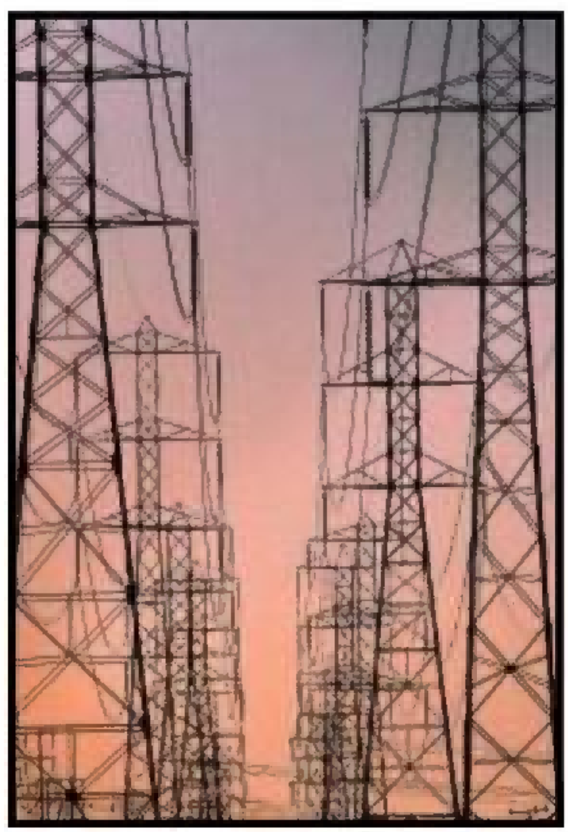
Non-jurisdictional entities that propose to build a transmission line that will operate at 69 kV or higher must first receive a certificate from the Siting Board. The requirements of KRS 278.714 do not address the need for the facility but do address siting issues such as the impact on Kentucky's scenic assets. New and developing technologies such as utilization of lightweight, non-metallic conductors and current limiting reactors can increase the capacity of existing transmission lines thus delaying or eliminating the need for new routes. Kentucky's electric utilities should be encouraged to investigate new and developing technologies that can increase the capacity of existing transmission facilities.

The Comprehensive Energy Bill signed into law by President Bush on August 8, 2005 contains provisions regarding the siting of the nation's bulk transmission grid. The provision may impact Kentucky's ability to regulate the siting of transmission lines within our borders.

The bill includes provisions to require the DOE to study and designate "national interest electric transmission corridors." Within one year from the date of enactment of the Bill and each three years thereafter, DOE, in conjunction with affected states, will designate these corridors based upon transmission capacity constraints or congestion that adversely affects consumers. There are many factors taken into consideration when making this designation, but in part, DOE may consider (1) whether economic vitality or development in a corridor or in end markets served by the corridor are constrained due to the lack of adequate or reasonably priced electricity; and (2) whether the designation would be in the interest of national energy policy. This designation as a "national interest electric transmission corridor" is important because once these corridors are selected, FERC has authority to site transmission facilities within these corridors if states cannot or will not site the facilities within one year.

Kentucky's situation between northern and southern load centers, coupled with the aforementioned constraints on north-south power transfers within Kentucky, present the possibility that one or more "national interest electric transmission corridors" through Kentucky will be identified. That designation will give FERC siting jurisdiction if Kentucky fails to certificate, within 1 year, a request for transmission expansion in the identified corridors for facilities within that corridor. It is not yet determined who will pay for these transmission facilities to be constructed, although it is safe to assume that such information would be included in any request for such a transmission certificate.

The Commission agrees with recommendation number 43 of the Energy Policy Task Force's *Comprehensive Energy Strategy*. Kentucky should ensure its "place at the table" with the federal energy regulatory agencies to protect the interests of the Commonwealth, particularly with regard to any designation of national interest transmission corridors and development of regional electricity markets.



Resource Adequacy-Distribution

Electric distribution utilities are companies that provide electric service to end-use residential, commercial and industrial customers. Distribution facilities include power lines, facilities operating at voltages of less than 69 kV, and service line drops to customer meters. A a map showing the distribution utilities in Kentucky and their territories follows on the next page.

There are three types of electric companies providing distribution service in Kentucky: rural electric distribution cooperatives, municipal utilities and investor-owned utilities. The majority of the 24 distribution cooperatives are jurisdictional, 3 of which purchase their power from Big Rivers and 16 of which purchase their power from East Kentucky Power, and are commonly described as generation and transmission cooperatives. Currently, there are five non-jurisdictional distribution cooperatives operating in Kentucky that purchase their power from TVA. The 30 municipal utilities that provide distribution service in Kentucky are not regulated by the Commission.

New Technology

While none of the electric utilities identified any pure research projects in which they were involved regarding distribution reliability, efficiency, or safety improvement, they indicated that they are actively evaluating and implementing new technology and other means to improve the efficiency and reliability of their distribution systems. The Commission believes that such activity is important and should be continued. We encourage the electric utilities to review and analyze the research of new technologies, products and programs proposed in the new federal energy bill and currently performed by The Edison Electric Institute, the Electric Power Research Institute and other electric industry organization that performs such research. Where practical, the Commission encourages the electric utilities to share such information with their peers.

Distribution System Reliability

The Commission believes that electric distribution utilities should be encouraged to explore proven state of the art technology to implement cost-effective electric service reliability improvements. While the electric utilities responded that they had implemented reliability improvement programs, there were significant differences in the degree of sophistication of the programs. The Commission believes that it is important for each electric distribution utility to have formal programs to improve and maintain acceptable reliability levels. Such programs should include: (1) load forecasts; (2) formal system reviews; (3) targeted objectives; and (4) appropriate procedures to guide field personnel. In terms of the targeted objectives, the use of the SAIDI, System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) indices, as well as other indices that may be appropriate, should be used to determine system-wide and localized feeder benchmarks against which performance can be measured each year. This, along with other information, could assist the electric utilities in identifying the distribution feeders with the poorest reliability and planning appropriate corrective action.

The establishment of a single state-wide reliability standard for use by all electric utilities in Kentucky may be impractical, given the diverse geographic characteristics and population density of the State. However, the Commission believes that it is important that each utility utilize standard criteria in the calculation of its own internal indices to enable some form of comparison among the utilities. This could include establishing standard criteria for excluding major events, the units of time to be used, and the detail to which system reliability will be measured. This could also assist utilities in establishing consistent benchmarks to measure annual or periodic performance. The electric utilities could use this information to objectively evaluate the effectiveness of their reliability improvement programs and provide greater consistency when reporting the results of their reliability improvement programs to the Commission or other regulatory bodies.

Right-Of-Way Maintenance and Vegetation Management

An effective ROW or vegetation management program, cutting trees or branches which may come into contact with distribution lines, can help reduce outages during storms or severe weather. We are also aware that for all the benefits ROW clearing can provide, property owners, for aesthetic reasons, are sometimes hesitant to allow the utilities to trim or cut their trees.

There is no current regulation in Kentucky which specifies the frequency or width of ROW clearance for distribution lines. When asked at the technical conference about the need to establish such a standard, all the jurisdictional electric utilities stated that it would be appropriate for the Commission to address this issue with each individual utility in the context of a rate case, but that standard clearance parameters should not be established. The Commission recognizes the difficulties electric utilities can encounter with property owners regarding ROW clearing. Furthermore, we are concerned that the reluctance of some property owners to allow proper trimming of their trees negatively impacts the reliability of entire distribution systems. Perhaps through the establishment of a distribution ROW clearance requirement, the electric utilities' ability to keep branches away from their lines and improve the reliability of the electric service would be enhanced. Therefore, the Commission believes that further consideration should be given to the establishment of some practical distribution vegetation management clearing parameters for Kentucky's jurisdictional electric distribution utilities.

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Energy Efficiency, Demand-Side Management and Conservation

In 1994, the General Assembly enacted legislation that was codified as KRS 278.285, which allows jurisdictional utilities to submit DSM plans and request recovery of DSM costs outside a general rate case through a DSM surcharge. Since that time, formal DSM plans and cost-recovery mechanisms (more commonly known as DSM surcharges) have been approved by the Commission for Kentucky Power, KU, LG&E, and ULH&P. While not submitting formal plans, both Big Rivers and East Kentucky Power, in conjunction with their member cooperatives, have developed and offered DSM programs to the retail customers of the member systems.

Although the jurisdictional utilities have a number of DSM programs in place, because of relatively low electric rates, many programs that have been cost-effective in other regions have not been shown to be cost-effective in Kentucky. However, as the incremental cost of new generation continues to increase, as fuel costs increase and as new environmental requirements increase the cost of all generation, the Commission believes that utilities will need to give greater consideration to energy efficiency measures, DSM programs, and conservation programs as tools for addressing a larger portion of their customers' demand.

As the costs of fuels for generation increases, and the costs of burning and disposing of those fuels increases as well, the relative costs of efficiency measures, conservation and DSM programs are expected to become more competitive with the costs of generation. This will result in greater investment by the electric utilities in efficiency, conservation and DSM measures.

Many aspects of the expanded role of DSM and energy efficiency measures recommended by the Kentucky Resources Council (KRC), Energy Systems Group, LLC (ESG) and other parties are beyond the scope of utility operations as well as the jurisdiction of the Commission. However, they are consistent with many of the recommendations contained in the *Comprehensive Energy Strategy* developed by the Commonwealth Energy Policy Task Force.

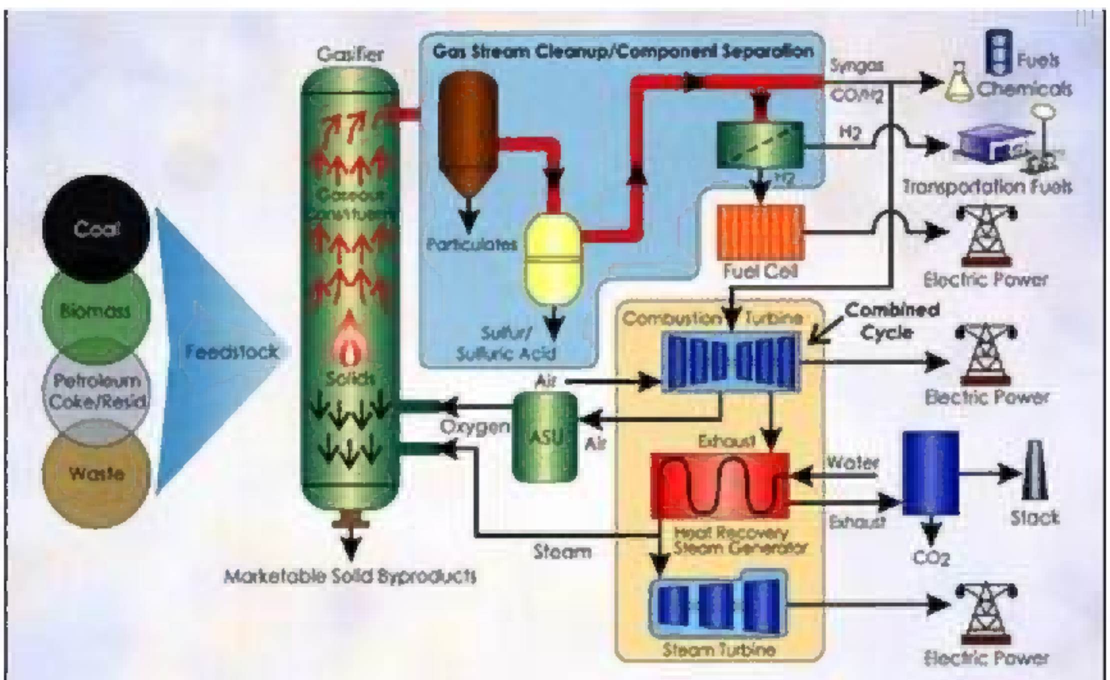
Promoting energy efficient practices, examining building codes, and increasing public awareness and education on energy efficiency issues are efforts that the Commission believes should be pursued by Kentucky's public policy makers. As we also note in discussing environmental compliance issues, greater use of energy efficient products and enhanced efforts to implement practical DSM and conservation measures can have a positive impact on the environment and should be considered in the development of Kentucky's future energy policy.

Efforts to implement practical DSM and conservation measures can have a positive impact on the environment.

Renewables and Alternative Technologies

As Kentucky's generating fleet ages and needs to be replaced, and as environmental requirements become more restrictive, the use of renewables and alternative generation technology becomes more important and cost-effective. Many jurisdictional and several non-jurisdictional electric utilities currently offer their customers the option of purchasing "Green Power," which is derived from renewable sources. However, due to the higher cost to generate power from most renewable resources, "Green Power" is sold at a premium price. In addition, most of the jurisdictional generating utilities indicated that they or their affiliates are investigating the use of renewables and alternative generation technology. These include biomass, hydro, solar, wind as well as IGCC and other clean coal technology. Also, all jurisdictional electric utilities have filed net-metering tariffs pursuant to KRS 278.466, which was enacted to promote the use of small scale renewables by residential and commercial customers.

Recommendation 18 of he Governor's *Comprehensive Energy Strategy* calls for the design and implementation of policies to promote, rather than mandate, the use of renewable energy resources as part of Kentucky's energy portfolio. The Commission, therefore, believes that it is important to encourage utilities and other interested parties to work to expand the use of renewables. Kentucky's energy policy should consider the value of renewables and provide appropriate financial



Integrated Gasification Combined Cycle (IGCC) incentives to those investing in generation using renewables so that such generation becomes economically viable for use by Kentucky's utilities. Such incentives could include grants, low interest loans, and tax credits.

Some participants urged that the full cost of environmental impacts and other externalities be included in the price of coal-fired electricity to reduce the cost differential between coal-fired generation and renewables or other alternative technologies. However, the Commission does not believe such a step is necessary or appropriate at this time.

As we state in the Externalities and Environmental Compliance sections of this report, the identification and quantification of the related costs is impractical. In addition, the inclusion of externalities in the price of electricity implies that those that consume electricity are solely responsible for the existence of the externalities. Such implication may be inaccurate and thus result in an inappropriate transfer of costs.

Other states have assured rate recovery or granted higher returns on investments in renewable generation. These actions would raise the cost of electricity to Kentucky's consumers and are less preferable than other identified incentives at this time.

In addition to incentives for investment, it is also important that Kentucky's energy policy include an effort to educate the public regarding the benefits of renewables.

Other than renewables, IGCC technology was the predominant clean coal technology discussed in this proceeding. Like renewables, this technology is also currently more expensive than conventional fossil fuel generation. In addition, there are still concerns regarding the operating reliability of this developing technology, although the predominant manufacturer, GE, is taking steps to mitigate this risk. Some now argue that IGCC units may be the generation choice of the future because of the ability to sequester carbon dioxide (CO_2).

As with renewables, the *Comprehensive Energy Strategy* included a recommendation to promote investment in clean-coal technology. With regard to more expensive IGCC technology, it is unclear whether it would be eligible for a CPCN under KRS 278.020 or how its environmental benefits could be accounted for in an environmental surcharge proceeding under KRS 278.183. Financial incentives similar to those that may be developed for renewables should be available for IGCC or closely related technology. One additional financial incentive discussed for IGCC investment that should be considered is that of securitization.

(As described by KIUC, securitization is a financing option that allows a utility to finance assets with 100 percent debt at the most attractive investment grade rates. A rate mechanism such as a surcharge would charge all customers benefiting from the financing until all bonds have been repaid. Securitization would require specific legislation.)

Externalities

The comments of the non-utility panel participants and members of the public participating at the technical conference heavily referenced externalities, which generally refer to external costs imposed without being accounted for in the cost of a product. The most significant of the externalities identified were emissions from coal-fired generating units. These are addressed in a separate Environmental Compliance section because environmental compliance is an issue that has an overriding impact on every resource acquisition decision of the electric utilities.

In this proceeding, the Commission heard from those who advocate including the full cost of externalities in the price of electricity. Neither the electric utilities nor other parties who might disagree have had the opportunity to comment or rebut the comments of those who advocate the inclusion of externalities in the price of electricity. The pros and cons should be considered and evaluated before any determination is made regarding externalities in relation to Kentucky's energy policy.

The costs of some externalities are already included in the price of electricity. The costs to comply with environmental emissions requirements are included in the utilities' generation resource acquisition decisions as well as in the evaluation made with regard to retrofitting existing generating units. In addition, most of the jurisdictional generators have implemented environmental compliance plans and environmental surcharges. The costs of land reclamation, compliance with regulations and other costs relating to coal production are included in the cost of coal. However, the potential exists that all related externalities are not fully included in the cost of coal since coal is a commodity and subject to competitive market pressures. To address the ideal proposed by some participants in this proceeding and include the full cost of externalities in the price of electricity would certainly increase the price of electricity or reduce utility revenues. There may be undesired or unintended consequences as a result.

The Commission believes that cautious consideration must be given to the inclusion of any externality in the price of electricity. The inclusion of externalities in the price of electricity implies that those that consume electricity are solely responsible for the existence of the externalities. Such implication may be inaccurate and thus result in an inappropriate transfer of costs. The Commission does not have jurisdiction under KRS Chapter 278 to explicitly allow for consideration of such externalities.

Environmental Compliance

As noted above, the jurisdictional utilities are required to comply with numerous environmental requirements as part of doing business. Although state and federal agencies other than the Commission are responsible for enforcing environmental compliance, the Commission deals with utilities on environmental issues in a number of ways. These include: (1) integrated resource planning; (2) filings made pursuant to KRS 278.183, the environmental surcharge statute; and (3) CPCN proceedings for approval to construct environmental facilities.

As part of their IRP, the utilities are required to forecast their demand and energy sales for a 15-year planning horizon and demonstrate how they plan their resources to meet those forecasts. They must include environmental impacts in the criteria used to screen potential resource options, identify the actions to be taken during the planning horizon to comply with the Clean Air Act Amendments of 1990, and describe how those actions will affect their resource plan. The environmental compliance measures identified within the IRP proceeding often come before the Commission at a later date as part of a utility's application for an environmental surcharge under KRS 278.183 or for a CPCN under KRS 278.020(1).

In an environmental surcharge proceeding, a utility may seek to recover environmental compliance costs through an environmental surcharge. To do so, it must file a plan that addresses compliance with applicable federal, state, or local requirements, and it must relate only to generating electricity through coal combustion. The plan must address a reasonable return on related capital expenditures and include a tariff that establishes the terms and conditions of the surcharge. The Commission must determine whether the plan and surcharge are a reasonable and cost-effective means of (1) complying with the applicable environmental requirements and (2) recovering the related costs.

Depending on specific components of a utility's environmental compliance plan, a CPCN application may be submitted for Commission approval to install specific environmental comliance facilities at the utility's generating units. Such CPCN proceedings, which are covered by the provisions of KRS 278.020(1), have typically involved flue gas desulphurization systems, commonly known as "scrubbers," and selective catalytic reduction facilities (SCRs). These facilities, that cost millions of dollars, are necessary to comply with environmental emissions standards for fine particulates and chemicals such as sulfur dioxide and nitrogen oxide that are released during generation.

It is through these various regulatory proceedings that the Commission and Commission Staff monitor and review the manner in which utilities pursue compliance with environmental standards, implement their compliance plans, and seek to recover the related costs.

Currently, four utilities, East Kentucky Power, Kentucky Power, KU and LG&E, are operating under Commission approved environmental surcharges. Big Rivers had an environmental surcharge for approximately three years but terminated it prior to its bankruptcy filing. ULH&P, which currently purchases its power from its parent company, has not requested an environmental surcharge.

The compliance related capital investments included in all of the environmental compliance plans approved for the jurisdictional utilities total $2.068 billion. The following is a breakdown of investments by utility:

Company	**Investment Pursuant to an Approved Environmental Compliance Plan**
Big Rivers	**$208.4 million**
East Kentucky Power	**$198.7 million**
Kentucky Power	**$172.6 million**
Kentucky Utilities	**$1,163.4 million**
Louisville Gas & Electric	**$324.9 million**

Clearly, the cost of environmental compliance has had a significant impact on the cost of generating electricity. In fact, no other cost has had the impact of environmental compliance in recent years. Accordingly, each jurisdictional electric generating utility stated, in some fashion, its concern with the likelihood of more restrictive environmental requirements and increased costs to comply.

The Commission shares this concern. However, as previously noted, the Commission lacks jurisdiction relating to environmental requirements which are, for the most part, federally mandated. The Kentucky Environmental and Public Protection Cabinet (EPPC) has some limited authority; however, the majority of its efforts are to implement and enforce the federal requirements which, as it notes, are expected to become more restrictive.

As EPPC notes, even though the use of coal for electricity generation has increased by 75 percent since 1970, total power plant emissions have declined by 40 percent. While we share the concerns noted by KRC and other participants regarding environmental related externalities (other than environmental compliance related), we do not believe it is appropriate to place an additional cost burden on electric customers as some suggest. In this proceeding, the utilities have indicated their willingness to implement sound and reasonable environmental policy. In their resource plans, the utilities have considered and evaluated the latest technology. Kentucky's electric utilities should not be punished for burning coal. The Commission believes that Kentucky's environmental policy should be balanced. We encourage the electric utilities, the EPPC and other appropriate agencies and organizations to participate at the federal level to ensure that sound environmental policy is developed.

The Governor's Energy Policy Task Force also indicated its concern with environmental issues. The *Comprehensive Energy Strategy* contains no fewer than 20 recommendations relating to environmental issues, including: (1) promoting the use of energy efficient products and educating the public regarding their benefits; (2) promoting the use of renewables and alternative generation technologies including clean coal technology; (3) continuing aggressive policies regarding mine-site reclamation and the recovery of abandoned coal refuse; and (4) addressing the general concern of environmental quality. The Commission agrees with these recommendations and believes that these efforts should be part of Kentucky's future energy policy.

Kentucky's electric utilities have already taken some of the steps included in those recommendations. All the electric utilities offer DSM programs and provide incentives for the purchase and installation of energy efficient products. Pursuant to KRS 278.466, all have tariffs to allow net-metering. Most are evaluating or participating in the evaluation of renewables and alternative technology while some are already generating power from alternative technology.

As noted in the Energy Efficiency, Demand-Side Management and Conservation section of this report, the greater use of energy efficient products and DSM will result in a lower demand for electric energy. We believe that research on and development of energy efficient products and the use of renewables and alternative technology for electricity generation should be encouraged in developing Kentucky's future energy policy, and that incentives such as tax credits, grants and low interest loans should be considered to foster such activities.

Barriers to Infrastructure Investment

The focus of the pre-filed and oral comments regarding barriers to investment varied among the groups represented at the technical conference. The jurisdictional utilities and MEPAK cited barriers to their investment in facilities to serve their customer base. The comments of other participants were as diverse as the groups they represented, and, with the exception of Kentucky Pioneer and Peabody Energy, generally addressed barriers to investment in alternatives to coal-fired generation.

At the technical conference each jurisdictional utility representative adopted and seconded the comments made by their peers. For jurisdictional utilities, barriers included: merchant plants, change in tax policy, environmental compliance, federal versus state authority, deregulation, and rate uncertainty.

Merchant plants were noted as barriers because some believe they would reduce the available emissions capacity and negatively impact the environmental compliance options available to regulated utilities. This issue is addressed in the Merchant Plant section of this report.

The tax policy change refers to the Kentucky Revenue Department's decision that distribution and substation transformers are subject to sales tax based on its re-interpretation of a Revenue Department Circular. East Kentucky Power, itself, has been assessed almost $2 million for the period from February 1, 2001 through November 30, 2004. This policy change will impact all jurisdictional electric utilities and, given the estimate of East Kentucky Power, the impact could be significant.

The Commission was unaware of this tax policy change until it was identified in this proceeding. We are not familiar with the legal basis or other reasons for this change in tax policy, nor would we normally have reason to be. However, within the context of the Governor's directive, we note that under traditional rate-making principles an increase in taxes assessed to a regulated electric utility will increase its cost to serve customers and will eventually result in a rate increase, all other factors being equal. The Commission recognizes the responsibility of all citizens and companies to bear their fair share of Kentucky's tax burden. Therefore, the Commission recommends that this issue be considered in Kentucky's energy policy in the context of its overall impact on both electricity rates and taxes.

The jurisdictional electric utilities identified the issues of environmental compliance and federal versus state regulation as top issues facing Kentucky's electric power industry in the future and as the two most significant barriers. The issue of environmental compliance is addressed in an earlier section of this report.

The need to define the regulatory roles of the federal and state governments was specifically set forth by Kentucky Power in its comments but seconded by the other jurisdictional utility panelists at the technical conference. The issue of jurisdictional certainty encompasses a number of sub-issues relating to wholesale energy markets, transmission tariffs, the transmission grid itself, RTOs, siting of new facilities (particularly transmission) and generation needs. Each jurisdictional electric utility agreed that the federal government, through the FERC, has regulatory authority over wholesale energy markets, transmission tariffs, and generally the transmission grid. This Commission has authority over the provision of retail electric service including the rates for wholesale transmission when provided as part of a bundled retail sale. However, the distinction between the two has become somewhat ambiguous and continues to be so, particularly with regard to the emergence of RTOs.

Each jurisdictional electric utility addressed this ambiguity from the perspective of the issues important to them. Big Rivers discussed RTO membership and the absence of benefits of joining an RTO, arguing that Kentucky should reject RTO membership unless increased reliability, lower costs, or other benefits to offset the costs of membership can be demonstrated. East Kentucky Power also addressed the issue of RTOs, noting that while there may be operational advantages there are cost disadvantages. East Kentucky Power recommended that Kentucky prevent its utilities from joining RTOs unless membership is shown to be economically prudent. To support its position, East Kentucky Power discussed the negative impact of accommodating Transmission Loading Relief orders (TLRs) and its perception that there is a lack of coordination between MISO and other regions.

Kentucky Power briefly discussed transmission siting authority as an issue of concern, stating that FERC should have siting authority and the power of eminent domain relative to the transmission grid. In comments at the technical conference, Kentucky Power qualified its prior position by stating that it intended for such federal power to be used when states were barriers to transmission investment and that transmission siting was working in Kentucky. Kentucky Power cited a 90-mile transmission line an affiliate is constructing in Virginia and West Virginia that required 15 years to receive approval even though it was needed for reliability. Kentucky Power also stated that Kentucky needs to retain authority over generation and transmission. Finally, Kentucky Power recommended that Kentucky look into the "whole picture of RTOs" and capacity markets because of the economic consequences.

KU and LG&E also expressed concerns relating to RTOs. They cited decisions relating to generation dispatch and DSM, noting that state authority over these areas is being impacted by RTOs and wholesale energy markets. As members of an RTO, KU and LG&E indicate that they are now subject to a form of federal regulation focused primarily on regional issues rather than Kentucky issues and that this regulation hinders the Commission's ability to regulate solely in the best interests of Kentucky.

(The membership of KU and LG&E in MISO is currently under review by the Commission in Case No. 2003-00266, Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities in the Midwest Independent Transmission System Operator, Inc. Subsequent to the establishment of that case, KU and LG&E gave notice to MISO of their intention to withdraw their membership.)

ULH&P, which is in the process of acquiring several generating units from its parent, recommended that the Commission work with the National Association of Regulatory Utility Commissioners (NARUC) and FERC to define the boundaries of jurisdiction relating to resource adequacy issues, more specifically those involving transfers of generating units between utility affiliates. ULH&P also discussed issues relating to RTOs. It indicated its concern with generation and transmission siting, which formerly involved only the utility.

Now siting is regional in focus and may be multi-regional because of ULH&P's membership in MISO and Kentucky Power's membership in PJM. ULH&P is also concerned with its ability to recover transmission related costs and recommended that the Commission approve trackers to recover such costs.

MEPAK also cited the issue of RTOs in its comments. MEPAK stated that its members rely on the transmission systems of others and noted the need for reasonable transmission costs, and it stated its concern that RTOs are costly with few benefits.

The Commission shares the concerns of the jurisdictional electric utilities regarding the issue of federal versus state jurisdiction. In the past, the Commission has intervened in cases before FERC to preserve its jurisdiction or to assert its rights. For example, in FERC Docket No. ER03-262-009, the Commission supported its authority to approve or deny Kentucky Power's application to join PJM, aggressively opposing FERC efforts to preempt the Commonwealth's jurisdiction. The list of issues spawned by the creation of RTOs is growing and the Commission is seemingly faced with ever decreasing authority as FERC addresses new issues regarding RTOs and transmission. Recognizing that RTOs are predominantly federally driven, we are unsure as to how Kentucky's energy policy can incorporate plans to address this issue.

Legislation has been passed in recent sessions of Kentucky's General Assembly to expand Kentucky's and the Commission's jurisdiction. Examples of such legislation include: (1) the 2002 enactment of statutes, KRS 278.700-278.716, creating the Siting Board, authorizing that Board to approve or disapprove the siting of non-regulated generation and transmission plants; (2) the 2003 enactment of KRS 278.216 extending many of those Siting Board requirements to Commission cases in which regulated utilities seek certificates for most generating plants; and (3) the 2004 amendment of KRS 278.020 giving the Commission jurisdiction to approve or disapprove major regulated transmission projects.

However, such actions cannot preserve the Commission's limited authority. Recommendation 43 of the *Comprehensive Energy Strategy* calls for Kentucky to engage federal regulatory and energy agencies to ensure Kentucky has "a place at the table" in the discussion of energy issues, and Recommendation 44 calls for Kentucky to investigate the impact of global and national policies on our energy future. The Commission fully supports these recommendations and will make its staff available to assist the Executive Branch, Kentucky's Legislative Branch and our federal legislators in this endeavor. In addition, we recommend that Kentucky's future energy policy include sufficient flexibility so that the Commonwealth may react to federal action quickly and efficiently.

ULH&P, whose parent, CG&E, operates in a restructured environment in Ohio, identified deregulation as a concern. ULH&P cited the California energy crisis, the bankruptcies of Enron and Mirant, and the fact that retail

competition could result in higher rates for Kentucky customers as reasons to be cautious regarding deregulation. ULH&P urged the Legislature and Commission to continue a "wait and see" approach.

Pursuant to House Joint Resolution 95, passed in the 1998 legislative session, the Commission Staff, during 1999 and 2000, participated with staff of the Legislative Research Commission (LRC) and an independent consultant to review the issue of electric restructuring in Kentucky. The findings, which were presented to the Special Task Force on Electric Restructuring (Special Task Force) generally found that there were few positive benefits to Kentucky and that there was no compelling reason for Kentucky to restructure.

(The Special Task Force was established by Joint Resolution 95 during the 1998 legislative session of the General Assembly. The Special Task Force consisted of 20 members

from both the executive and legislative branches and was charged with assessing the impact of allowing electric retail competition in Kentucky.)

As a result, the Special Task Force recommended that the 2000 General Assembly take no action to restructure Kentucky's electric industry. Since that time, several factors, not the least of which are the California energy crisis and Enron's bankruptcy, have caused states that were restructuring to reassess and reconsider their efforts. The Commission believes, as the report to the Special Task Force suggests, that in the future Kentucky may be forced to move toward restructuring as a result of federal legislation and FERC actions.

Changes are already taking place as the result of open access transmission and the establishment of RTOs and competitive energy markets run by RTOs. The Commission still believes that Kentucky should continue its "wait and see" approach. We agree with the recommendation that Kentucky must have a place at the table in these discussions and work to maintain our status as a low cost energy state.

The barriers and other issues identified by other participants reflect concerns specific to the interests that they represent. Many of these, such as requiring increased investment in DSM programs and more energy efficient products, as well as the barriers to investment in merchant plants, renewables and alternative technologies, are addressed in other sections of this report; however, some are addressed here.

MEPAK discussed the lack of joint action authority as a significant barrier to investment. This is an issue important only to the municipal systems. In summary, joint action authority would enable the municipal systems to combine load and bonding capacity to enable them to acquire high grade financing at a lower cost than is currently available.

The issue of joint action authority is beyond the Commission's authority. The Commission has no jurisdiction over the municipal electric utilities and no authority regarding possible joint action legislation. We would, however, be concerned about such legislation to the extent that it could impact the jurisdictional utilities.

Regulatory Certainty

The Commission recognizes that changes within the electric industry in recent years have created greater uncertainty than previously existed. However, we believe that the regulatory scheme in Kentucky has been successful, as many parties stated, due in part to the measured and deliberate approach that has been taken to address various issues.

To the extent that cost recovery and regulatory certainty are concerns, it is worth noting that when new rates are filed, the five- and six-month suspension periods established in KRS 278.190 are among the shortest in the nation. Furthermore, the utilities have been assured of timely recovery of increases in fuel costs through the use of a fuel adjustment clause under the provisions of 807 KAR 5:056, which was established in 1978.

In addition, utilities have the ability to recover the costs of environmental compliance on a nearly real time basis via an environmental surcharge, pursuant to KRS 278.183, which was established in 1992. Finally, DSM costs, including lost revenues and financial incentives, have been recoverable via a DSM surcharge since 1994, when the General Assembly enacted KRS 278.285.

Having made these points, it is not our intent to imply that regulation should stand still. There clearly is greater uncertainty today than in the past and we would be remiss in our responsibility if we did not seek ways to improve on the existing practices and procedures employed by the Commission. Securitization, an issue raised by KIUC, is something we believe merits further consideration. We also believe that the issue raised by Meade County RECC concerning the operation of our CPCN process for distribution cooperatives is a matter that should be taken under advisement.

The issues raised by Alcan and Century are both serious and complex. It is true that competitive energy markets have not evolved as Alcan and Century expected. It appears that the discussion in this case of how the smelter loads will be served beyond the expiration dates of their existing contracts has merely scratched the surface of the issues that could impact how this matter may be resolved. We believe that this issue will require further detailed review by numerous parties, including the Commission, the smelters, Big Rivers, Kenergy, LG&E Energy as lessee of Big Rivers' generation, and representatives of the state and local governments.

The regulatory scheme in Kentucky has been successful due in part to the measured and deliberate approach that has been taken to address various issues.

Conclusion

As previously noted, Kentucky's electric utilities, both jurisdictional and non-jurisdictional, currently either have adequate generation, transmission and distribution to serve their customers, or are actively working to meet customers' needs. Moreover, Kentucky's utilities have demonstrated that they are adequately planning to serve the needs of their customers through 2025. Given the absence of identifiable benefits to "restructuring" or "deregulating" Kentucky's electric utility industry at this time, the Commission concludes that Kentucky should preserve its current statutory and regulatory framework, which focuses primarily on the utilities' obligation to serve the electrical needs of customers within a defined service territory.

Within the current framework, however, there are no guarantees that future electricity prices in Kentucky will continue to be the lowest in the nation. The current fleet of coal-fired electric power plants in Kentucky accounts for much of our low-cost power. Portions of this fleet are aging and subject to future environmental restrictions. As aging infrastructure is replaced, new costs will have to be paid by Kentucky ratepayers.

Assuming FERC and the congress continue to promote the development of regional wholesale electricity markets, Kentucky must work to ensure that the interests of Kentucky's ratepayers and utilities are represented. This is true for other federal policy developments, such as environmental and eminent domain issues, which will affect Kentucky's future electricity prices and availability.

Because the U.S. electric power industry is changing, Kentucky should consider policies to protect or insulate Kentucky ratepayers from market uncertainties and the price implications of future environmental restrictions. On the other hand, given the economic benefits of Kentucky growing as an energy exporter, policy makers should also give consideration to opportunities for Kentucky citizens, businesses, and communities to benefit from greater participation in energy markets. In either case, a balanced approach will be necessary to preserve Kentucky's low-cost energy, responsibly develop Kentucky's energy resources, and preserve Kentucky's commitment to environmental quality.

Among the immediate uncertainties facing the electric power industry in Kentucky are: federal policies regarding the development of regional electricity markets and air emission standards; ability to site new electric generation and transmission facilities; factors affecting coal production and the price of coal; and technologies that will improve the efficiency of electricity production and use. Policy and technological developments with regard to these issues will directly affect electricity rates in Kentucky. Given the importance of low electricity rates for Kentucky, both as a tool for recruiting and retaining businesses, as equally as a necessity for all its citizens, the Commonwealth must continually evaluate its policies to mitigate the risks associated with generating, transmitting and distributing electricity.

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
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 amount of electric power delivered or required over a given period of time at a steady rate within a 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	Wholesale power transferred in large quantity across high voltage lines.
Bundled Services	Combining all costs into one rate, as opposed to separate charges for generation, transmission and energy services.
CAIR	Clean Air Interstate Rule; Pollution Reduction Strategy targeting the reduction of SO_2 and NOx.
CAIDI	Customer Average Interruption Duration Index; A distribution Reliability measure that represents the average time to restore service.
Capacity	The limit at which a generator, turbine, transformer, transmission circuit, substation or system can produce or carry electricity for extended periods per manufacturers ratings.

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	An overload condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously.
Control areas	An electric power system in which a common automatic control scheme is applied in order to maintain power supply and demand, maintain system frequency, and provide sufficient generating capacity to sustain sufficient operating reserves.
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 24 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	The rate at which electric energy is delivered to or by a system at a given instant or over a designated period of time.
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.
Distribution system	The portion of an electric system that delivers electric energy to an end-user through low-voltage lines.
Diversity Exchange	An exchange of capacity or energy, or both, between electric systems whose peak loads occur at different times.

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 Power	East Kentucky Power Cooperative, Inc.
Economy transactions	The purchase of power when it is less expensive than one's own generation, for a limited duration. This power is typically provided on an interruptible basis.
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
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.
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 that encourage wholesale competition in electricity by requiring transmission owners to permit other parties to utilize the existing system to transfer wholesale generated electricity to end-users.
FERC Order 889	Regulations issued by FERC which require transmission system owners to make the terms and conditions of transmission services available to the public at the same time that the information is available 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	Power intended to be available at all times during the period covered by a guaranteed commitment to deliver, 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 end-users a provider is obligated to serve within its franchised service territory.
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 end-users, 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.
IGCC	Integrated Gasification Combined Cycle; Clean coal technology aimed at meeting environmental goals by joining coal gasification and combined cycle to maximize energy output.
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.

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 – A written plan that demonstrates 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 good utility 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
KU	Kentucky Utilities Company. An affiliate of LG&E owned by LG&E Energy.
LEM	LG&E Energy Marketing, Inc.; an unregulated affiliate of LG&E.
LG&E	Louisville Gas & Electric Company an affiliate of KU owned by LG&E Energy.
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 million watts. 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.
M ISO	Midwest Independent System Operator an RTO whose Kentucky members include KU, LG&E and ULH&P.
Municipal utility	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 end-user electrical demand in a utility's service territory. For a G & T cooperative, the electric demand in its member distribution cooperatives' service territories.
North American Electric Reliability Council (NERC)	A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of 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 that allows 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.
Outage	The period during which a generating unit, transmission line, or other facility is out of service.
OVEC	Ohio Valley Electric Corporation
PJM	PJM Interconnection, LLC. An RTO of which Kentucky Power is a member.
Peak demand	The maximum load during a specified period of time.
Peaking unit	Generating equipment normally reserved for elevated demand during the hours of the highest daily, weekly or seasonal loads.

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 make service available to an end-user within a providers service territory.
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. MISO and PJM are the two RTOs with Kentucky members.
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.
Reserve margin	The amount of unused available capability of an electric power system for a utility system at peak load as a percentage of total capability.
Restructuring	See deregulation.
Return on equity (ROE) component	The financial return on investment that regulatory authorities allow investor-owned utilities.
SAIDI	System Average Interruption Duration Index; A distribution reliability index that indicates the duration of interruption for an average customer.
SAIFI	System Average Interruption Frequency Index; A distribution reliability measure that represents how often an average customer experiences a sustained interruption.

Selective Catalytic Reduction (SCR)	Equipment used to remove nitrous oxides from boiler plant combustion gases prior to atmospheric discharge.
SEPA	Southeast Power Administration
Substation	Equipment that switches, changes or regulates electric voltage.
Stranded costs	Prudent costs incurred by a utility, which may not be recoverable under market-based retail competition. Examples are un-depreciated generating facilities, deferred costs, and long-term contract costs.
Tariff	A document that lists the terms, conditions and prices under which utility services – approved by a regulatory agency - will be provided.
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. A process controlled by system operators to relieve transmission congestion by re-routing power flow within an existing grid.
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. .
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.
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.
Wholesale transactions	The purchase and sale of electricity from generators to organizations that sell to retail customers.

APPENDIX B

AN APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2005-00090 DATED September 15, 2005

SUMMARY OF PROCEEDINGS

INDEX

<u>BACKGROUND</u>

The following "summary of proceedings" discusses the detailed information submitted in response to data requests. The discussion also includes a summary of the pre-filed comments of the participants in a June 14, 2005 Technical Conference. Oral comments made at the conference and written comments filed subsequent to the conference are also included. Certain publicly available information is also discussed and referenced as appropriate.

As discussed in more detail below, Kentucky has six major jurisdictional electric utilities that own or are in the process of acquiring generation. They include four investor-owned utilities: Kentucky Power; KU; LG&E; ULH&P, and two generating and transmission cooperatives ("G&Ts"): Big Rivers and East Kentucky Power. Collectively, Kentucky's jurisdictional electric utilities serve about 1.8 million customers. There are also 30 municipal electric systems and five TVA supplied distribution cooperatives, which provide retail electric service, that are not subject to the Commission's jurisdiction. TVA owns generation in Kentucky and serves a limited number of retail customers in western Kentucky. The non-jurisdictional electric utilities serve about 375,000 customers.

A summary discussion of the information compiled on the generation and supply resources and planning and reserve requirements is provided in the following discussion for each jurisdictional generating utility and for the non-jurisdictional electric utilities as a whole. In addition, tables listing the jurisdictional and non-jurisdictional generating units sited in Kentucky are shown below:

Electric Generation in Kentucky

Jurisdictional Generation

East Kentucky Power Cooperative, Inc.

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Dale	Clark	four	196	coal	1954-1960
Cooper	Pulaski	two	341	coal	1965, 1969
Spurlock	Mason	three	1,459	coal	1977, 1981, 2005
Smith CTs	Clark	seven	842	gas	1999, 2001, 2005
Bavarian Landfill	Boone	one	3	methane	2004
Green Valley Landfill	Greenup	one	2	methane	2004
Laurel Ridge Landfill	Laurel	one	3	methane	2004

Kentucky Power Company

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Big Sandy	Lawrence	two	1,060	coal	1963, 1969

Kentucky Utilities Company

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Dix Dam	Garrard	three	24	hydro	1925
E.W. Brown	Mercer	three	697	coal	1957, 1963, 1971
E.W. Brown	Mercer	seven	849	gas	1994-2001
Ghent	Carroll	four	1,945	coal	1974-1984
Green River	Muhlenberg	two	163	coal	1954, 1959
Haefling	Fayette	three	36	gas	1970
Lock 7	Mercer	three	NA	hydro	1927
Tyrone	Woodford	two	58	oil	1947-1948
Tyrone	Woodford	one	71	coal	1953

Louisville Gas and Electric Company

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Cane Run	Jefferson	three	563	coal	1962-1969
Cane Run	Jefferson	one	14	gas	1968
Mill Creek	Jefferson	four	1,472	coal	1972-1982
Ohio Falls	Jefferson	eight	48	hydro	1928

Paddys Run	Jefferson	three	193	gas	1968, 2001
Trimble County	Trimble	one	383	coal	1990
Trimble County	Trimble	six	960	gas	2002, 2004
Waterside	Jefferson	two	22	gas	1964
Zorn	Jefferson	one	14	gas	1969

The Union Light, Heat & Power Company[1]

Generating Station	County	No. Units	MW	Fuel	Initial Operation
East Bend	Boone	one	414	coal	1981

Non-Jurisdictional Generation

Municipal Generation

Generating Station	County	No. Units	MW	Fuel	Initial Operation
HMP&L – Station 1	Henderson	two	2	gas	1948
HMP&L – Station 1	Henderson	two	44	coal	1956, 1968
OMU - Smith Station	Daviess	two	425	coal	1964, 1974
City of Paris	Bourbon	seven	12	fuel oil	1934-1974

Federally-owned Generation

Tennessee Valley Authority

Generating Station	County	No. Units	MW	Fuel	Initial Operation
TVA - Paradise	Muhlenberg	three	2,331	coal	1963, 1970
TVA - Shawnee	McCracken	ten	2,611	coal	1953-1956
TVA-Kentucky Dam	Livingston	five	197	hydro	1944-1948
U.S. Army Corps of Engineers					
Laurel Dam	Laurel	one	70	hydro	1977
Barkley Dam	Lyon	four	130	hydro	1966
Wolf Creek Dam	Russell	six	270	hydro	1951-1952

[1] ULH&P should close the transaction to acquire this generation later in 2005. The other generating units it will acquire are Miami Fort 6 and Woodsdale 1-6, which are located in Ohio.

Merchant Generation

Dynegy

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Dynegy – Foothills	Lawrence	two	460	gas	2002
Dynegy - Riverside	Lawrence	three	690	gas	2001
Dynegy – Bluegrass	Oldham	three	624	gas	2002

Western Kentucky Energy[2]

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Reid	Webster	one	65	coal	1966
Coleman	Hancock	three	455	coal	1969-1972
HMP&L Station 2	Webster	two	405	coal	1973-1974
Reid CT	Webster	one	65	fuel oil	1976
Green	Webster	two	454	coal	1979-1981
Wilson	Ohio	one	420	coal	1986

Cogeneration Generation

Generating Station	County	No. Units	MW	Fuel	Initial Operation
Cinergy Silver Grove	Campbell	one	20	gas	2001
Weyerhauser Ky. Mills	Hancock	one	88	wood waste	2001
Cox Waste to Energy	Taylor	one	4	wood waste	1995
Air Products Calvert City	Marshall	one	27	gas	2000

[2] Generation owned by Big Rivers and Henderson Municipal Power and Light ("HMP&L") and leased to WKE, a non-utility operator.

Big Rivers - Resource Summary

Existing Generation/Supply Resources

Big Rivers is a not-for-profit G&T which provides power at wholesale to three member/owner distribution cooperatives, Jackson Purchase Energy Corporation ("Jackson Purchase"), Kenergy Corp. ("Kenergy"), and Meade County RECC. These distribution cooperatives provide retail electric service to approximately 107,000 customers in 22 western Kentucky counties.[3] As part of an agreement arising from its 1996 bankruptcy filing, Big Rivers leases all of its generating facilities to Western Kentucky Energy ("WKE"), an unregulated affiliate of LG&E and, in a companion transaction, purchases power from LG&E Energy Marketing, Inc. ("LEM"), another unregulated affiliate of LG&E, through 2023.[4]

Big Rivers historically had the largest industrial load of any G&T because it supplied power to two aluminum smelters, Alcan and Century. However, as part of its reorganization, the smelters' firm loads are now supplied by LEM under separate power contracts with Kenergy.[5] Currently, Big Rivers has 597 MW available from LEM plus 178 MW available from the Southeast Power Administration ("SEPA"), through the U.S. Army Corps of Engineers, for a total of 775 MW.[6] In 2012, Big Rivers' capacity will

[3] Pre-filed Comments of Big Rivers, dated June 8, 2005 at 2.

[4] Administrative Case No. 387, A Review of the Adequacy of Kentucky's Generation Capacity and Transmission System, Order dated December 20, 2001 at 13.

[5] The issue of the continued provision of service to the smelters beyond the expiration of their contracts in 2010 and 2011 was raised by Alcan and Century in this proceeding and is discussed in the Rate Certainty, Cost Recovery and Other Regulatory Issues section.

[6] Administrative Case No. 387, Order dated December 20, 2001 at 23.

increase to 978 MW, with 800 MW available from LEM along with the 178 MW available from SEPA.[7]

Resource Planning

Resource planning is integral to Big Rivers' overall planning processes. Like the other major jurisdictional electric utilities, Big Rivers files an Integrated Resource Plan ("IRP") with the Commission on a triennial basis. Big Rivers assists its three member distribution cooperatives in determining their overall power requirements and combines those requirements to arrive at the Big Rivers system's annual load forecast for a 15-year planning horizon. Big Rivers determines the amount of supply resources required for each year. It compares these requirements with the resources available under existing, firm power supply contracts to assure sufficient power is available to meet its obligations to its members.[8]

Big Rivers and its member distribution cooperatives screen Demand-Side Management ("DSM") measures through cost/benefit analyses to determine acceptable DSM measures to initiate.[9] Big Rivers provides financial participation (in the form of end-user incentive payments) and technical support to its distribution cooperatives for the following programs: (1) Add-on heat pump; (2) All Electric Touchstone Energy Home; and (3) Electric water heater. Not all of Big Rivers' distribution cooperatives offer all programs.[10] A detailed discussion of Big Rivers' DSM programs and the energy

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[7] Big Rivers' Response to Staff's Data Request to Big Rivers and Kenergy, dated May 27, 2005 at 3.

[8] Big Rivers' Response to Staff's First Data Request, dated March 10, 2005, Item 1.

[9] Id.

[10] Id., Item 17.

efficiency related services available to residential, commercial and industrial customers through Jackson Purchase, Kenergy, and Meade County RECC is included in the Energy Efficiency, Demand-Side Management and Conservation section. Big Rivers' budgets for the incentive programs are shown below:[11]

2005	2006	2007 and beyond
$136,950	$174,250	$255,500

Resource Adequacy

As noted above, through 2011, Big Rivers will have 775 MW of generation available from LEM and SEPA. During this period, its base case forecast projects native load demand to reach 703 MW, while its high case demand forecast is 728 MW,[12] either of which can be met under Big Rivers' power supply contracts. Beginning in 2012, Big Rivers will have 978 MW in generation available from LEM and SEPA. In 2017, the last year in Big Rivers' forecast horizon, its base case forecast projects native load demand to be 780 MW. Under its high case forecast, Big Rivers projects its native load demand in 2017 to be 829 MW.[13] Again, these demands can be adequately met with the 978 MW Big Rivers will have available beginning in 2012.

Under its base case forecast, Big Rivers projects steady demand growth of 10 MW to 14 MW annually for the period 2005 through 2017, with average growth of 12.2 MW a year in its forecast. In its high case forecast, the annual average projected

[11] Id.

[12] Id., Item 7.

[13] Id.

growth is 14.9 MW.[14] Even under its high case forecast, Big Rivers' projected peak demand will not exceed the 775 MW contractual capacity that it has available from LEM and SEPA through 2011 or the 978 MW of contractual capacity available from the same sources through 2023, the last year of its contract with LEM.[15] Big Rivers has also included a minimum level of 50 MW of firm off-system sales per year,[16] which it will also be able to meet with its contractual capacity.

Because it purchases 100 percent of its system power requirements under purchases that are considered "financially firm," with contracts that provide for liquated damages in the event of non-performance, Big Rivers does not have a formal planning reserve margin.[17] Finally, Big Rivers has no plans to add base load or peaking capacity in the years from 2005 through 2017. Nor does it plan to retire any generating capacity during this period.[18]

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[14] Calculated from Big Rivers' Response to Staff's Data Request, dated March 10, 2005, Item 7.

[15] Although Executive Order 2005-121 calls for a review of resource adequacy through 2025, Big Rivers' most recent load forecast only extends through the year 2017. It should also be noted that Big Rivers' existing SEPA contract expires in 2016 and its LEM contract expires in 2023. This statement assumes its SEPA power contract will be extended beyond 2016.

[16] Big Rivers' Response to Staff's First Data Request, dated March 10, 2005, Item 7.

[17] Id., Item 8.

[18] Id., Items 11 and 16.

East Kentucky Power - Resource Summary

Existing Generation/Supply Resources

East Kentucky Power is a not-for-profit G&T utility which provides wholesale electric service to 16 member/owner distribution cooperatives in 89 counties throughout eastern and central Kentucky. Through these distribution cooperatives, it serves approximately 475,000 retail customers.[19] In addition to its owned generation, which consists of 1,996 MW of coal-fired, base load capacity and 842 MW of natural gas-fired peaking capacity,[20] East Kentucky Power has 170 MW of capacity available under a contract with SEPA.[21]

Resource Planning

East Kentucky Power's planning cycle begins with its load forecast and consists of developing a capacity expansion plan and identifying potential financial impacts of implementing the plan. It develops a load forecast with input from all member systems every two years in accordance with the Rural Utilities Service ("RUS") requirements. It files an IRP every three years with the Commission. East Kentucky Power's evaluation of capacity needs is based on its latest load forecast, a capacity technology assessment, a screening analysis of capacity alternatives, including DSM, and a risk assessment of its expansion plan. The plan is simulated and input into East Kentucky Power's financial model to determine the impact on its margins and rates. The base plan is reviewed and re-evaluated as necessary. A long-term financial forecast is

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[19] East Kentucky Power's 2004 Annual Report.

[20] East Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 10.

[21] Administrative Case No. 387, Order, dated December 20, 2001 at 25.

developed annually which includes updated fuel costs and East Kentucky Power's base case expansion plan with adjustments.[22]

Capacity additions are generally made through a Request for Proposals ("RFP") process in which East Kentucky Power exercises no control over the technologies bidders may offer. New technologies may be offered as self-build options if they are considered mature enough to be reliable. Circulating fluidized bed ("CFB") boiler technology, such as the Gilbert Unit that became commercial in March 2005, is a relatively new technology for coal-fired generation. East Kentucky Power is presently planning to add at least two more coal-fired units using this same CFB technology.[23]

Three years ago, East Kentucky Power began investigating the use of methane gas produced naturally at landfills to generate electricity. After completing an evaluation of the economics of these projects, East Kentucky Power constructed three landfill gas plants in 2003 and a fourth plant is planned for completion in late 2005. East Kentucky Power is studying methane recovery from certain industrial waste processes for electric generation. It is also studying wind as a potential renewable energy resource.[24]

In 2008, Warren Rural Electric Cooperative Corporation ("Warren RECC") will become a member of East Kentucky Power and will receive wholesale power service. Following the issuance of an RFP and review of those proposals, East Kentucky Power applied to the Commission for a Certificate of Public Convenience and Necessity ("CPCN") to construct a 278 MW CFB coal-fired unit at its Spurlock Station to serve

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[22] East Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

[23] Id., Item 2.

[24] Id., Item 3.

Warren RECC's load in 2008.[25] That case is currently pending before the Commission. East Kentucky Power also has pending a second application for a certificate to construct a 278 MW CFB coal-fired unit and five 90 MW combustion turbines at its J.K. Smith Station with an in-service date of 2009.[26] Projects identified by East Kentucky Power with in-service dates beyond 2009 are placeholders for future capacity additions. No commitments have yet been made for those projects.[27]

East Kentucky Power's resource plan includes a significant number of gas-fired combustion turbines which are planned to meet peaking needs and some intermediate load needs. Forecasts of future fuel prices are also prepared and they are updated for use in preparing major power supply studies or the triennial IRP.[28]

East Kentucky Power, in conjunction with its member distribution cooperatives, offers various DSM programs, the majority of which are residential. One non-residential program is interruptible rate pricing, a program on which East Kentucky Power currently has 124 MW of interruptible demand.[29] The DSM programs currently offered are

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[25] Case No. 2004-00423, Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity, and a Site Compatibility Certificate, for the Construction of a 278 MW (Nominal) Circulating Fluidize Bed Coal Fired Unit in Mason County, Kentucky.

[26] Case No. 2005-00053, Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity, and a Site Compatibility Certificate, for the Construction of a 278 MW (Nominal) Circulating Fluidized Bed Coal fired Unit and Five 90 MW (Nominal) Combustion Turbines in Clark County, Kentucky.

[27] East Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 11.

[28] Id., Item 13.

[29] Id., Item 17.

discussed in detail in the Energy Efficiency, Demand-Side Management and Conservation section.

Resource Adequacy

East Kentucky Power's base case forecast projects a system peak demand of 2,633 MW in 2005 and a system peak demand of 5,158 MW in 2024. Its high case forecast projects peak demands of 3,028 MW and 5,861 MW in 2005 and 2024, respectively.[30] Unlike many of the other major utilities in Kentucky, East Kentucky Power's system peak consistently occurs during the winter, rather than the summer.

East Kentucky Power uses a 12 percent target reserve margin, which, from a planning perspective, it meets during the summer with its owned generation and SEPA power purchases.[31] However, it purchases blocks of firm power during the winter months to meet its reserve margin.[32]

East Kentucky Power has not retired any generating units since 2000,[33] and has no plans to retire any existing generating units through 2025.[34]

Kentucky Power - Resource Summary

Existing Generation/Supply Resources

Kentucky Power, a subsidiary of American Electric Power Company, Inc. ("AEP"), a multi-state public utility holding company, serves approximately 175,000

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[30] Id., Item 7.

[31] Id., Item 8.

[32] Id., Item 9.

[33] Id., Item 15.

[34] Id., Item 16.

customers in 20 counties in eastern Kentucky. Of its total available capacity of 1,450 MW, Kentucky Power owns 1,060 MW of coal-fired generation, and purchases the other 390 MW from an AEP affiliate under two unit power agreements. These unit power agreements, under which Kentucky Power purchases power from the Rockport Generating Station in southern Indiana, run through December 7, 2022.

AEP has nine subsidiaries which are operating utilities providing electric service in 11 midwest and south-central states through the AEP-East and AEP-West power pools. Kentucky Power, along with four other AEP subsidiaries, is a member of the AEP-East power pool, and collectively they serve customers in seven states.[35]

Resource Planning

Planning for Kentucky Power is performed by AEP, which conducts resource planning for the AEP-East power pool on a system-wide basis. AEP forecasts future customer demand and energy requirements, including committed sales to unaffiliated systems, and establishes a "target" which the system's resources must be able to serve with adequate reliability. It applies reliability or reserve criteria and determines how much reserve capacity is required to meet the requirements with a specified level of reliability. The result of this process is reduced to an equivalent reserve percentage based on more detailed analyses.[36]

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[35] Administrative Case No. 387, Order, dated December 20, 2001 at 32.

[36] Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

AEP reviews the adequacy of current and planned resources to meet the system's needs. This involves making a projection of the system's current and committed resources, taking into account anticipated capacity additions and retirements and currently scheduled purchases. This is then compared with its projected load requirements, taking into account reserve requirements to determine the need for additional resources. Any projected capacity deficiencies identified in this process indicate a need for additional resources. The pattern of such needs over time establishes the outline of required resource additions.

AEP reviews available future resource options including different types of supply-side resources such as new generation, generating unit ownership arrangements, power purchases, special opportunities, etc., as well as demand-side resources. AEP catalogs the various engineering, operational, and cost characteristics of each resource as part of determining the mix of resources that produces a low cost, reliable resource plan. AEP compares the total costs of owning and operating the system assuming different mixes of resource options, keeping in mind that flexibility in a capacity resource plan is a major advantage.[37]

AEP monitors and revises all steps of the planning process on an ongoing basis, as appropriate. Updated estimates become available from time to time and are taken into account as practicable. Implementing the plan involves implementing feasibility analyses which may include additional analyses regarding the plan's financing

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[37] Id.

requirements, specific ownership arrangements, etc. Once the plan is finalized, acquisition of the selected resources is arranged.[38]

AEP is evaluating a mix of generation resources to meet the AEP-East power pool's projected capacity needs through 2015. AEP projects it may need additional capacity resources by 2006. Until then, capacity needs will probably be met through purchases from the market on an as-needed basis. Prior to 2015, AEP also expects to construct and/or acquire generation facilities in the AEP-East power pool, but the precise timing, technology mix, location, and size of such additions remain under review.[39]

DSM planning is generally performed at the same time as capacity resource planning but is performed on a utility specific basis. The evaluation process for DSM begins by establishing a DSM measure database, performing preliminary screening, and then analyzing the cost-benefit of the DSM measure. The DSM measures that pass the cost-benefit test are combined with supply-side models and the participant cost-benefit is analyzed. Finally, the DSM measures that pass those tests will be implemented with a follow-up review to verify performance.[40]

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[38] Id.

[39] AEP has researched and continues to evaluate integrated coal gasification combined cycle ("IGCC") technology. AEP is still considering whether to site an IGCC unit in Kentucky, Indiana or Ohio.

[40] Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

Kentucky Power administers a formally approved DSM program under which it recovers costs through an applicable DSM surcharge.[41] Kentucky Power's DSM budget for 2005 is $678,250.[42]

Resource Adequacy

Kentucky Power's projected load and capacity, and the projections of load and capacity for the other members of the AEP-East power pool, indicate that Kentucky Power's obligation for additional capacity could be up to 500 MW by 2015.[43] Kentucky Power's base case and high case demand forecasts include projected peak demands in excess of its available capacity in every year from 2005 through 2024.[44] In the early years of this forecast period, Kentucky Power expects to meet its peak demand requirements with purchases of capacity from other members of the AEP-East power pool and occasional purchases in the wholesale market as it has done in recent years.[45] However, Kentucky Power needs to purchase capacity for relatively few hours during the year.

The AEP-East power pool is now a member of PJM, a regional transmission organization which has operational control of the AEP-East power pool's transmission system, and therefore, Kentucky Power's transmission system. The AEP-East power

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[41] DSM programs and DSM surcharges are discussed in detail in the Energy Efficiency, Demand-Side Management and Conservation section.

[42] Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 7.

[43] Id., Item 11.

[44] Id., Items 7 and 9.

[45] Id., Item 11.

pool is required to comply with PJM's reserve margin requirements. PJM has set the Installed Reserve Margin for the June 2005 through May 2006 planning period at 15.0 percent. Using current AEP reliability and diversity factors, this translates into an Installed Reserve Margin for AEP of 14.07 percent. This compares with a 12 percent margin that AEP used, based on its own determinations, from the late 1990s until joining PJM.

AEP has not established a fixed reserve margin for Kentucky Power.[46] Kentucky Power is expected to provide its share of the AEP-East power pool's capacity on a proportionate basis, as opportunities arise. Within the next several years, Kentucky Power and AEP expect that new generation will be added by one or more members of the AEP-East power pool and that Kentucky Power will share in the ownership and cost responsibility, to some extent, of this new generation.[47] Kentucky Power has no plans to retire any of its existing generating capacity,[48] but may experience reductions in existing capacity if additional emission controls are required.[49]

It should be noted that, in conjunction with the long-term extension of the Rockport purchase power agreements, Kentucky Power's next IRP is to be filed no later than June 30, 2009. However, the next IRP could be filed earlier if there are significant changes to the provisions governing the operation of the AEP-East power pool.

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[46] Id., Item 8.

[47] Id., Item 11.

[48] Id., Item 16.

[49] Id., Item 14.

KU and LG&E - Resource Summary

Existing Generation/Supply Resources

KU provides electric service to approximately 485,000 customers in 77 counties throughout central, southeastern and western Kentucky. LG&E is a combination gas and electric utility serving approximately 389,000 electric customers in the greater Louisville - Jefferson County area and eight surrounding counties.[50] KU and LG&E merged in 1998 but have retained their separate corporate identities. They are both subsidiaries of LG&E Energy LLC., a public utility holding company. While each utility owns its own generation, it is all jointly dispatched. All generation planning is also performed on a joint basis. In addition to their owned generation, KU and LG&E, through long-term contracts, have access to 200 MW of generating capacity from Electric Energy Inc. ("EEI"), 179 MW from Ohio Valley Electric Corporation ("OVEC"),[51] and 195 MW from Owensboro Municipal Utility ("OMU").

In addition to existing generation, KU and LG&E have jointly proposed to construct a 732 MW (summer rating) super-critical pulverized coal-fired base load generating unit at LG&E's Trimble County Station ("Trimble County No. 2"). KU and LG&E will own 75 percent, or 549 MW, of the new unit. The Illinois Municipal Electric Agency ("IMEA") and the Indiana Municipal Power Agency ("IMPA"), which own 25 percent of the Trimble County No. 1 coal-fired unit, intend to own 25 percent of Trimble

[50] KU 2004 Annual Report, LG&E 2004 Annual Report.

[51] Staff estimate based on FERC filings.

County No. 2.[52] Applications relating to the construction of Trimble County No. 2 are currently pending before the Commission and the Kentucky State Board on Electric Generation and Transmission Siting Board ("Siting Board").

Resource Planning

KU and LG&E review planning alternatives and decisions annually as part of an ongoing resource planning process. Detailed resource planning is performed every three years as part of their joint IRP process. Demand and energy forecasts are prepared annually. In the integrated resource planning process, the economics and practicality of supply-side and demand-side options are examined to determine cost-effective responses to their customers' needs. The steps undertaken in this process are: (1) establishment of a reserve margin criterion; (2) assessment of the adequacy of existing generating units and purchase power agreements; (3) assessment of potential purchased power market agreements; (4) assessment of demand-side options; (5) assessment of supply-side options; and (6) development of an economic plan from the available resource options. Screening of DSM options is also performed as part of this joint IRP process.[53]

KU and LG&E have individually approved DSM programs with applicable DSM surcharges. A summary of the major existing DSM programs is included in the Energy

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[52] Case No. 2004-00507, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity, and a Site Compatibility Certificate, for the Expansion of the Trimble County Generating Station, filed December 17, 2004 and, KU's and LG&E's Response to Staff's Data Request, dated March 10, 2005, Item 10.

[53] KU's and LG&E's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

Efficiency, Demand-Side Management and Conservation section. The DSM budget for each company through 2007 is as follows:[54]

	2005	2006	2007
KU	$4,519,843	$4,642,473	$4,586,962
LG&E	$5,080,519	$5,223,187	$5,188,434

Resource Adequacy

KU's and LG&E's base case forecast projects a combined peak demand of 6,696 MW in 2005, growing to 8,794 MW by 2019. In their high case forecast, they project a combined peak demand of 6,748 MW in 2005 growing to 9,402 MW by 2019.[55] In order to meet the growth projected in their base case forecast and maintain an adequate reserve margin, they plan to add approximately 2,100 MW of coal-fired base-load capacity, 900 MW of natural gas-fired peaking capacity, and 180 MW of hydro capacity over the next 20 years.[56]

The combined companies established an optimal reserve margin range in 2002 of 13 percent to 15 percent, with 14 percent recommended for planning purposes. The reserve margin analysis included in the KU and LG&E 2005 IRP recommends a range of 12 percent to 14 percent, while maintaining a 14 percent reserve margin for planning purposes.[57]

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[54] Id., Item 17.

[55] Id., Item 7.

[56] Id., Item 11, rounded.

[57] Id., Item 8.

KU and LG&E have no current plans to retire any existing generating units during the 2005 and 2025 period. However, KU and LG&E stated that some retirements are likely in the future due to the age of some units and the expected economics associated with future environmental compliance.[58] KU and LG&E have over 1,300 MW of generation that is 35 years old or older.

ULH&P - Resource Summary

Existing Generation/Supply Resources

ULH&P, a wholly-owned subsidiary of The Cincinnati Gas & Electric Company ("CG&E"), is a combination gas and electric utility serving approximately 122,000 electric customers in five counties in northern Kentucky. CG&E is a wholly-owned subsidiary of Cinergy Corp., a registered public utility holding company. ULH&P currently owns no generation. It has historically relied on CG&E to provide 100 percent of its power requirements via wholesale purchased power contracts.[59] The current wholesale power contract expires at the end of 2006. In response to the concerns expressed by the Commission in Administrative Case No. 387 regarding ULH&P's exposure to market based prices for electricity, ULH&P proposed to acquire 1,105 MW of generating capacity from CG&E. The Commission initially approved the

[58] Id., Items 15 and 16.

[59] Administrative Case No. 387, Order, dated December 20, 2001 at 35.

acquisition of these generating facilities on December 5, 2003 in Case No. 2003-00252.[60] The transaction has received all required approvals, except that of the Securities and Exchange Commission ("SEC").[61]

The transaction approved by the Commission also allows ULH&P to take power from CG&E when ULH&P's generation is not available; however, ULH&P will solicit bids for its back-up power supply needs and other parties will have an opportunity to beat the bid price offered by CG&E.[62]

Resource Planning

Development of ULH&P's IRP involves two major processes, one organizational and one analytical. The organizational process involves the formation of an IRP team with representatives from key functional areas of Cinergy. The analytical process involves these steps: (1) develop planning objectives, assumptions and a load forecast; (2) screen potential demand-side resource options; (3) screen, and perform sensitivity analysis of the cost-effectiveness of potential supply-side resource options; (4) screen, and perform sensitivity analysis of the cost-effectiveness of potential environmental compliance options; (5) integrate the demand-side, supply-side and environmental

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[60] Case No. 2003-00252, The Application of The Union Light, Heat and Power Company for a Certificate of Public Convenience to Acquire Certain generation Resources and Related Property; for Approval of Certain Purchase Power Agreements; for Approval of Certain Accounting Treatment; and for Approval of Deviation from Requirements of KRS 278.2207 and KRS 278.2213(6), Interim Order, dated December 5, 2003.

[61] Id. at 2.

[62] Id., Final Order, dated June 17, 2005 at 5 and 6.

compliance options; (6) perform final sensitivity analyses on the resource alternatives and select the plan; and (7) determine the best way to implement the chosen plan.[63]

ULH&P's resource planning considers both demand-side and supply-side resources. On the demand-side, it plans on implementing all cost-effective DSM programs, subject to the receipt of all necessary approvals. DSM programs are initially identified through a market potential analysis conducted by external consultants. All measures and programs so identified are evaluated for cost-effectiveness. The load impacts of the recommended DSM programs are also included as a component in ULH&P's IRP.[64] ULH&P has a formally approved DSM program with an applicable DSM surcharge. ULH&P periodically files with the Commission for approval of new DSM programs or for the extension of existing DSM programs. A brief description of the DSM programs currently offered by ULH&P is included in the Energy Efficiency, Demand-Side Management and Conservation section. The annual budget for ULH&P's DSM programs is about $2.5 million.[65]

New technologies are considered in Cinergy's generation planning processes. In addition to subcritical and supercritical pulverized coal units, fluidized bed units, advanced combustion turbines ("CTs") and combined cycle units, fuel cells, wind turbines, solar, biomass, and storage units are considered. Cinergy has not implemented the new generation technologies on a large scale commercial basis.

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[63] ULH&P's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

[64] Id.

[65] Id., Item 17.

Cinergy is currently involved in a detailed study with GE and Bechtel concerning the potential construction of an IGCC unit.[66]

Resource Adequacy

ULH&P's base case load forecast projects peak demands of 914 MW in 2005 and 1,116 MW in 2025, respectively. Its high case forecast projects a peak demand of 917 MW in 2005 and 1,178 MW in 2025.[67] ULH&P will be using a target reserve margin based on several components which have historically been used by CG&E. The components include: (1) operating reserve of four percent; (2) unscheduled outages - the greater of eight percent or the loss of the largest generating unit; and (3) weather-induced load forecast uncertainty identified as three percent. Upon the acquisition of its new generation, ULH&P will have a target reserve margin of 16.2 percent, which will gradually decrease to a 15 percent level by 2020 as its load grows.[68]

With a planning reserve margin of 15 to 16 percent, ULH&P projects that it will have no need for additional capacity until 2013. Since the first capacity addition after 2005 is not expected until 2013, and since it has no plans for the retirement of East Bend 2, Miami Fort 6, or Woodsdale 1-6, ULH&P indicates that its long-term capacity needs will continue to be reassessed on a going forward basis. Purchases from the wholesale market may be used to meet its reserve margin criteria during peak demand times in years prior to when it adds additional capacity.[69]

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[66] Id., Item 2.

[67] Id., Item 7.

[68] Id., Item 8.

[69] Id., Items 9, 11 and 16.

Non-Jurisdictional Electric Utilities - Resource Summary[70]

Existing Generation/Supply Resources

Electric service is also supplied to parts of Kentucky by 30 municipal electric systems, TVA, and five TVA supplied distribution cooperatives. None of these suppliers are regulated by the Commission. Two of the municipal systems, Henderson Municipal Power and Light ("HMP&L") and Owensboro Municipal Utilities ("OMU"), own their own generating facilities.[71] The majority of HMP&L's generation is operated and managed by WKE, a non-regulated affiliate of LG&E, pursuant to a lease agreement with Big Rivers. OMU operates its own facilities but the power in excess of OMU's needs is provided to KU and LG&E pursuant to a power purchase agreement. The rest of the municipal systems purchase power from TVA, KU, Kentucky Power or CG&E.

The 13 municipal systems supplied by TVA are typically served under indefinite term full-requirements contracts that can be terminated by either party upon five-years notice. According to the information provided in this proceeding, two systems, Glasgow and Princeton have given such notice.[72] Paducah's contract expires in 2009. The 12 municipal systems supplied by KU have full-requirement contracts with five-year cancellation notices, except for Berea whose contract has a three-year cancellation notice. The two systems supplied by Kentucky Power have contracts continuing

[70] Not all non-jurisdictional systems provided information in this proceeding. The Commission has attempted to verify all information.

[71] The city of Paris owns a 12 MW diesel generating unit used for peaking purposes. Its supplier, KU, can call upon the use of this generation for up to 200 hours per year.

[72] MEPAK's Response to the Commission's letter, dated April 28, 2005 at 1.

through the end of 2005.[73] One system is supplied by CG&E. The 28 municipal systems that purchase all or some of their generation and their providers are shown below:

TVA supplied municipal systems

Benton Electric System
Bowling Green Municipal Utilities
Glasgow Electric Plant Board
Franklin Electric Plant Board
Fulton Electric System
Hopkinsville Electric System
Jellico Electric & Water System
Mayfield Electric & Water System
Monticello Electric Plant Board
Murray Electric System
Paducah Power System
Princeton Electric Plant Board
Russellville Electric Plant Board

KU supplied municipal systems

Barbourville Utility Commission
Bardstown Municipal Utilities
Bardwell
Benham
Berea Municipal Utilities
Corbin Utilities Commission
Falmouth
Frankfort Electric and Water Plant Board[74]
Madisonville Municipal Utilities
Nicholasville City Utilities
Paris
Providence

Kentucky Power supplied municipal systems

Electric Plant Board of the City of Vanceburg
Olive Hill Electric Company

Cinergy supplied municipal system

Williamstown Utility Company

As noted above, five distribution cooperatives are currently supplied by TVA. They are as follows:

Hickman-Fulton Counties Rural Electric Cooperative Corporation
Pennyrile Electric
Tri-County Electric Membership Corporation

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[73] Id. at 2.

[74] The Frankfort Plant Board has access to a small amount of SEPA hydro power.

Warren Rural Electric Cooperative Corporation
West Kentucky Rural Electric Cooperative Corporation

Warren RECC gave its five-year notice to TVA in 2003. In 2008, it plans to become a member of East Kentucky Power.

Resource Planning

Resource planning for a large majority of the non-jurisdictional electric systems is performed by their wholesale power suppliers. However, some systems perform their own planning function. In addition, some systems utilize the service of an external consulting firm to perform their planning.[75]

Resource Adequacy

Kentucky's non-jurisdictional electric utilities tend to be primarily distribution systems served by either TVA, with no independent regulatory oversight, or by KU, Kentucky Power, or CG&E pursuant to wholesale power agreements under the Federal Energy Regulatory Commission's ("FERC") jurisdiction. As their non-jurisdictional status would imply, the Commission maintains little information on these utilities on a regular basis. However, the information provided in this proceeding indicates that these utilities, in conjunction with their wholesale power suppliers, have made and are making provisions for supplying their customers in the future. It should also be noted that, historically, KU and Kentucky Power have included the supply of wholesale power to the municipal systems they serve as part of their IRP filings with the Commission.

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[75] Based in part on MEPAK's Response to the Commission's Letter, dated April 28, 2005 at 5-8.

Merchant Plants

Kentucky Pioneer and Peabody Energy submitted comments and spoke at the technical conference regarding the merchant plant sector. Both entities have received conditional construction certificates from the Siting Board.[76]

At the time of its final Order in Administrative Case No. 387, December 20, 2001, the Commission and the Kentucky State Energy Policy Advisory Board ("Energy Board") had been made aware of 24 non-jurisdictional merchant plants proposed in Kentucky. Merchant plants in Oldham County and in Lawrence County had been constructed and were in operation prior to the establishment of the Siting Board.

In 2002, shortly after its creation, the Siting Board received notices from five entities that planned to submit requests for certificates to construct merchant plants in Kentucky; one of those requests has been withdrawn.[77] At present, the Siting Board has issued certificates of construction for four merchant plants and has one request pending. The proposed merchant plants that have given notice to the Commission are shown below:

[76] The Siting Board was created effective April 24, 2002 by an act of the Legislature.

[77] Notice was submitted by Kentucky Mountain Power, Thoroughbred Generation Company, Westlake Energy Corporation, Estill County Partners, and Kentucky Pioneer Energy. Westlake has withdrawn its request.

Company	Case No.	Date of Final Order	Results
Kentucky Mountain Power	2002-00149	9/5/2002	Conditional certificate
Thoroughbred Generating Co.	2002-00150	12/5/2003	Conditional certificate
Westlake Energy Corp.	2002-00171	4/14/2005	Withdrawn
Estill County Energy Partners	2002-00172	10/12/2004	Conditional certificate
KPE	2002-00312	11/10/2003	Conditional certificate
DTE Wickliffe	2005-00108	4/13/2005	Withdrawn
IMEA & IMPA[78]	2005-00152	Pending	Pending

The proponents of merchant plants have generally stated that newer merchant plants will be cleaner to operate than the regulated utilities' older base load plants and will enable these older plants to be retired.[79] In this case, the comments of both Kentucky Pioneer and Peabody Energy set forth that same position.

Kentucky Pioneer supports the construction and deployment of coal gasification technology, specifically IGCC technology, noting that IGCC units are "more efficient than conventional coal combustion" and produce less carbon dioxide.[80] Kentucky Pioneer provided several studies supporting the advantages and deployment of IGCCs and discussed innovative financing of IGCCs or other gasification plants. One study submitted by Kentucky Pioneer supports loan guarantees and other financial incentives. Another study sets forth a financing arrangement among the federal government, state public service commissions and equity investors aimed at reducing financing costs. A

[78] The Illinois Municipal Electric Agency and Indiana Municipal Power Agency filed Case No. 2005-00152 requesting a construction certificate for their purchase of 25 percent of KU's and LG&E's 732 MW Trimble County Unit 2. The remaining 75 percent of the unit will be non-merchant and jurisdictional.

[79] Administrative Case No. 387, Order, dated December 20, 2001 at 44 (comments of EPSA).

[80] Pre-filed Comments of Kentucky Pioneer, June 8, 2005 at 2.

final study includes recommendations for developing a single set of siting and permitting standards for IGCCs.

Two significant barriers, according to Kentucky Pioneer, are the application of current regulatory law in Kentucky and the lack of a level playing field between regulated utilities and non-regulated merchant plants. Kentucky Pioneer believes there are two problem areas regarding the law. First, the siting law requires that a preference be given to coal-fired merchant plants. However, according to Kentucky Pioneer, no mechanism exists to encourage the siting or construction of such plants. Second, Kentucky Pioneer notes that the law includes a preference to site merchant plants on existing utility sites but that actual implementation does not conform to this provision of the law.[81]

Peabody Energy's comments support clean coal generation but do not indicate a preference of one technology over another. Peabody Energy notes that new sub-or super-critical pulverized coal, CFB, and IGCC plants will be cleaner than and may displace existing units.[82] Peabody Energy suggests that Kentucky should recognize the economic value, for both the coal industry and the Commonwealth, of adding new clean generation, specifically mine-mouth generation, and selling the power out of state. Peabody Energy cites Illinois' recognition of this as the reason its 1,500 MW Prairie State Energy Campus project in Illinois has become the lead project over its Thoroughbred project in Kentucky.[83] Peabody Energy contends that exporting

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[81] Id. at 10.

[82] Id., Comments of Peabody Energy, June 20, 2005.

[83] Id. at 2.

Kentucky's coal-based generation would result in a decrease in the U.S. price of natural gas by lowering the demand of gas-fired electric generators.[84] Peabody Energy describes Kentucky's transmission system as "relatively weak" and notes that Kentucky has only two north-south high voltage lines.[85] Peabody Energy also discusses problems with the siting law in that it does not allow for an extension of a construction certificate exclusive of court proceedings.[86]

Resource Adequacy - Transmission

Existing Transmission Resources

The electric transmission system in Kentucky serves two primary purposes. One is to enable electric utilities to provide adequate, reliable electricity to their consumers in Kentucky; the other is to accommodate economic bulk, wholesale power transfers. Those transfers can be entirely within Kentucky, exported from Kentucky, imported into Kentucky, or transferred through Kentucky. Kentucky's electric transmission system is actually seven individual systems that are interconnected at numerous points throughout the state. These seven transmission systems are owned by five utilities regulated by the Commission, TVA and CG&E.[87]

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[84] Id. at 4.

[85] Id. at 3.

[86] Id. at 4.

[87] CG&E owns the transmission facilities located in northern Kentucky that are used to provide bulk power at wholesale to ULH&P.

Each transmission provider defines "transmission" slightly differently, but they all generally consider transmission facilities to be those operating at 69 Kilovolts ("kV") or higher, while distribution facilities are those operating below 69 kV.[88]

Big Rivers defines transmission as all line and station facilities from the interconnection points with neighboring utility systems and interconnections with generation facilities within its control area to the high voltage connection point at the distribution delivery stations and direct serviced industrial customer stations of its three member cooperatives. Big Rivers' transmission system consists of facilities operated at 345 kV, 161 kV, and 138 kV in its bulk delivery system along with 69 kV lines in its sub-delivery system.[89]

East Kentucky Power includes in its transmission definition all land, conversion structures, and equipment employed at a primary source of supply to change the voltage or frequency of electricity for the purpose of its more efficient or convenient transmission; all land, structures, lines, switching and conversion stations, high tension apparatuses, and their control and protective equipment between a generating or receiving point and the entrance to a distribution center or wholesale point; and all lines and equipment whose primary purpose is to augment, integrate or tie together the sources of power supply.[90]

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[88] Based on Staff's Analysis of the Responses to Staff's First Data Request, dated March 10, 2005, Item 18.

[89] Big Rivers' Response to Staff's First Data Request, dated March 10, 2005, Item 18.

[90] East Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 18.

Kentucky Power has three separate classes of lines designated as transmission. Facilities operating at voltages 230kV and above are defined as Extra High Voltage ("EHV"). Those operating between 138kV and 161kV are termed High Voltage ("HV") transmission. Facilities operating below 138 kV are designated as sub-transmission.[91]

KU, LG&E and ULH&P quite simply define transmission as any line operating at 69 kV or above.[92]

Transmission Miles by Voltage for Each Utility[93]

Voltage	**Kentucky Power**	**Big Rivers**	**CG&E**	**East Kentucky Power**	**KU and LG&E**	**TVA**
69	417	791	126	1,864	2,581	432
138	299	15	104	388	1,172	
161	46	341		333	559	1,008
345	9	68	61	60	482	
500					36	85
765	258					
Total Miles:	**1,029**	**1,215**	**291**	**2,645**	**4,930**	**1,525**

Transmission Planning

Kentucky transmission design has historically centered on local load and internal generation. All of the transmission providers follow National Electric Reliability Council (NERC) Planning Standards and the guidelines of their respective Regional Reliability

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91 Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item18.

92 KU's and LG&E's Response to Staff's First Data Request, dated March 10, 2005, Item 18 and ULH&P's Response to Staff's First Data Request, dated March 10, 2005, Item 18.

93 Numbers derived from the Public Service Commission's GIS database for Electric Transmission collected in 2001-2004.

councils. These standards, though voluntary,[94] specify continual evaluation of the system's ability to deliver anticipated power demands even if a critical element of the system is out of service. The standards also specify study of more severe scenarios such as having multiple facilities out at the same time. The standards specify that the system operate within its rated capacities with one critical element out of service and that the system can be controlled if multiple elements are out of service.

Big Rivers determines its load forecast by consulting with its three power cooperatives and determining their needs in a 15-year window. Big Rivers transmission related resource planning is reflected in three and fifteen year construction work plans. It follows two federal Rural Development recommended criteria (single contingency outages and double contingency outages) for analyzing the adequacy of its transmission system which are consistent with NERC planning standards. Further, an East Central Area Reliability Council ("ECAR") power flow model is utilized to analyze transmission congestion.[95] Big Rivers routinely considers transmission capacity increases as part of its transmission planning process.[96] Big Rivers addressed future import and export capabilities through power flow studies to evaluate alternative system improvements and potential interconnections needed to provide 450 MW of additional transmission service and the interconnection requirements for the proposed Peabody

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[94] The recently enacted Comprehensive Energy Bill authorizes FERC to establish mandatory reliability standards.

[95] Big Rivers' Response to Staff's First Data Request, dated March 10, 2005, Item 1.

[96] Id., Item 23.

Thoroughbred Power Plant.[97] Construction projects to be completed in the 2007 through 2009 timeframe include adding new transmission routes, re-conductoring existing routes and completing re-sag projects.[98]

East Kentucky Power's planning also begins with annual load forecasts developed from input from each of its member cooperatives. East Kentucky Power's goal of transmission planning is to ensure an adequate transmission system for an appropriate planning cycle through developing detailed models of sufficient accuracy on an annual basis. Screening of these models is performed to identify problems within a five year planning horizon.[99] East Kentucky Power's planning criteria specifies that the system be able to withstand the outage of any single generating unit in conjunction with the outage of a transmission element.[100] East Kentucky Power considers various solutions to address identified problems including re-conductoring of overloaded lines, upgrading existing transmission lines to higher voltage, and the need to construct new lines along existing transmission corridors.[101] East Kentucky Power has not conducted specific studies of the import or export capability of its transmission system but continues to utilize internal planning criteria to minimize outages. ECAR performs seasonal assessments of the bulk transmission system's ability to accommodate

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[97] Id., Item 24.

[98] Id., Item 23.

[99] East Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

[100] Id., Item 24.

[101] Id., Item 23.

imports into the region, exports out of the region, and transfers across the region, and these assessments include EKPC information.[102]

AEP develops expansion plans for Kentucky Power and the other AEP systems to ensure reliability. The planning process has not fundamentally changed since AEP joined PJM in October 2004. PJM develops a Regional Transmission Expansion Plan ("RTEP") on an annual basis and Kentucky Power, through AEP, participates fully in the RTEP development. AEP's planning criteria is consistent with the NERC Planning Standards and ECAR guidelines. Remedies are identified and budgeted as appropriate to ensure that system enhancements will be timed to address the anticipated deficiency. During real-time operations, transmission constraints are mitigated using congestion management systems and processes. Transmission reliability is maintained through a continuum of long-term planning, short-term operational planning, and real-time operations. As a member of PJM, each of these functions currently performed by AEP will be augmented by coordination with PJM.[103]

AEP routinely participates in various transmission system analyses for the AEP-East power pool. AEP annually submits an assessment of the AEP Transmission system to FERC. In addition, AEP participates in the following ECAR inter-regional studies: MAIN/ECAR/TVA, VCAR/ECAR/MAAC, and VACAR/AEP/Southern/TVA.[104] When it is determined that transmission lines meet the criteria for expansion, AEP routinely uses two methods. The first involves reconductoring (replacing currently

[102] Id., Item 24.

[103] Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

[104] Id., Item 24.

existing lines with new larger capacity, higher voltage lines) along existing right-of-ways while the second includes re-insulating and enhancing terminal stations to allow for higher voltage power delivery.[105]

The KU and LG&E transmission system is designed to withstand forced outages of a single generator, a single transmission element, two generators and a single generator and a single transmission element. The system is planned to deliver company-owned generator output and purchased generation (economic and/or emergency) to meet projected customer demands and to provide contracted firm transmission services, including any planned generation resources contained in the resource plan.[106] KU does not design for expected constraints or bottlenecks that do not impact its ability to serve its customer load or to meet its contracted firm transmission services.[107] However, when thermal limits are met and the need for expansion is identified, lines are evaluated for replacement with higher capacity (with higher thermal ratings) lines.[108] With regard to planning studies of the transmission system's import or export capability, KU and LG&E responded that the study undertaken as part of Administrative Case No. 387 was still current and can be relied on. That study, by the Commission's consultant with the participation of utility engineers, was performed using a computerized electronic flow analysis.[109]

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[105] Id., Item 23.

[106] KU's and LG&E's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

[107] Id., Item 22.

[108] Id., Item 23.

[109] Id., Item 24.

Cinergy performs transmission planning using an integrated model of its entire system which includes the ULH&P service area. Annual electric systems studies are performed to determine where and when system modifications are required to ensure that the load is adequately served. When these needs are identified, multiple solutions are developed, addressing not only the capacity need, but also providing opportunities to improve reliability and operating flexibility, utilizing a model of the entire system.[110] If transmission line upgrades are required, ULH&P investigates several methods to increase capacity such as: high temperature conductors, re-conductoring to a larger conductor, and upgrading existing circuits to higher voltages.[111] ULH&P has not prepared reports that specifically analyze its transmission system to import or export power. Because its system consists of a 69kV system designed primarily to handle native load, the necessity to conduct such a study is of minimal priority.[112]

Transmission System Reliability

Kentucky's transmission carriers are all actively implementing transmission reliability improvement programs. They measure and monitor reliability in a number of ways. The distribution reliability measures such as System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI") and Customer Average Interruption Duration Index ("CAIDI") are widely used for lower voltages. Two additional measures are used to evaluate the performance of the higher

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[110] ULH&P's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

[111] Id., Item 23.

[112] Id., Item 24.

voltage portion of the transmission system. Those measures are: percent of load served, and MWh of sales lost.[113]

Big Rivers provides electric service to its member distribution cooperatives' substations by way of its 69kV sub-transmission system, which it monitors using SAIDI and CAIDI. SAIDI and CAIDI results are included in a monthly outage report that is also provided to its member distribution cooperatives. At year-end, the SAIDI and CAIDI results are reviewed by a committee that includes operating personnel from the member distribution cooperatives to identify trends and necessary system improvements.[114]

East Kentucky Power uses the Average Service Unavailability Index ("ASUI"), which measures the number of minutes that its average load is out of service to determine its reliability performance. The ASUI is reported system-wide on a monthly basis. Each year an annual goal is established to promote reliability improvement, by taking 90 percent of the previous five-year average. A Service Restoration Team reviews system disturbances monthly and makes recommendations for management to consider. If management approves the recommendations, they are budgeted and later implemented.[115]

Kentucky Power measures reliability using the SAIFI and CAIDI indices. The reliability of the transmission system is monitored and assessed by historical trending of these indices for interruptions of transmission lines and stations, including distribution

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[113] Based on Staff's analysis of the responses to Staff's First Data Request, dated March 10, 2005, Item 31.

[114] Big Rivers' Response to Staff's First Data Request, dated March 10, 2005, Item 31.

[115] EKPC's Response to Staff's First Data Request, dated March 10, 2005, Item 31.

stations. Reliability improvement projects are evaluated and implemented on an AEP system-wide basis. Kentucky Power reports that as a direct result of the transmission reliability improvement activities, customer interruptions, caused by transmission outages, have trended downward the past several years.[116]

KU and LG&E measure transmission system reliability in terms of SAIDI and Transmission Forced Outage Rates ("TFOR"). TFOR is internally developed to quantify the effective unavailability of the transmission network due to unplanned outages. Reliability improvement projects are developed to maintain the adequacy of the system and replace obsolete or failed equipment.[117]

ULH&P has no transmission lines but does have a reliability improvement program that is discussed in the Distribution Resource Adequacy section.

Transmission System Constraints

A typical industry indicator of a transmission constraint is an occurrence of a NERC Transmission Loading Relief ("TLR") procedure at a level of 3a or higher. A TLR Level 3a is an occurrence of a transaction that was not allowed to be scheduled due to conditions or other higher priority transactions on the network. TLRs at Level 3b or above result in curtailment of non-firm, firm point-to-point schedules and/or interruption of connected load.[118]

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[116] Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 31.

[117] KU's and LG&E's Response to Staff's First Data Request, dated March 10, 2005, Item 31.

[118] Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 21.

Big Rivers experienced transmission loading and congestion problems, either due to actual flows or potential flows resulting from a contingency, at eight facilities during 2003 and 2004. These eight facilities accounted for 26 separate events, with the majority of the TLRs required at either the Hardinsburg 161-138 kV transformer or the Henderson Co. 138 kV tie. On occasion, Big Rivers' ability to import or export was limited by TLRs from constraints on other utility systems.[119]

East Kentucky Power has identified several calculated post contingency abnormal/emergency incidences affecting its system, yet has not encountered any actual occurrences which have exceeded the emergency rating for any extended period of time. From May 20, 2004 to March 21, 2005 the Boonesboro North 138kV transmission line reached its calculated continuous load rating on 13 separate occasions. Beginning in January 2003, the LG&E Blue Lick to East Kentucky Power Bullitt County 161 kV transmission line was impacted on 63 separate occasions for calculated post-contingency conditions. Several separate incidents have occurred in the transmission control area when East Kentucky Power was requested to take actions to assist in mitigating the congestion problems of other utilities. These TLR requests have limited economic purchases forcing East Kentucky Power to curtail imports and instead dispatch higher priced generation.[120]

TLR requests for the AEP-East power pool were provided but none of the constraints were for any of Kentucky Power's facilities. Kentucky Power's

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[119] Big River's Response to Staff's First Data Request, dated March 10, 2005, Item 21.

[120] East Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 21.

interconnections were largely unaffected by the TLRs since many of the constraints were remote from Kentucky. The completion of the 765 kV Wyoming-Jacksons Ferry transmission project in Virginia and West Virginia is expected to significantly reduce the number of TLRs for the AEP-East power pool.[121]

The information submitted by KU and LG&E identified numerous TLR requests, the duration of each constraint and the affected facilities. KU and LG&E identified over 500 TLRs from January 2003 to the present.[122]

The ULH&P system consists of a 69 kV system primarily designed, planned and operated to serve the area load. As a result of the nature of the transmission system, it has a very low response factor to power transfers, and therefore bottlenecks and capacity constraints have not been experienced.[123]

Transmission System Expansion

With the ever-growing need for electric power, Kentucky's utilities are planning to expand their transmission capabilities. In several instances, the expansion will address both native load needs and the capabilities to handle power moving through the Commonwealth and lessen the need for TLRs. A summary of these expansion plans follows.

Big River's transmission planning reflects its Long Range Transmission Plan (1995 – 2015) and work developed during its three most recent three-year Construction

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[121] Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 21.

[122] KU's and LG&E's Response to Staff's First Data Request, dated March 10, 2005, Item 21.

[123] ULH&P's Response to Staff's First Data Request, dated March 10, 2005, Item 21.

Work Plans. The 32 submitted projects include substation support, infrastructure upgrades, metering, additional line capacity, and new substations among other upgrades. No projects have been identified beyond 2015.[124]

East Kentucky Power operates with a ten-year planning window and noted that all planned projects are re-visited prior to actual construction. The projects identified by East Kentucky Power for this case include categories for new lines and substations (27 itemized projects), line rebuilds/re-conductoring (35 itemized projects), and line upgrades (22 itemized projects).[125]

Kentucky Power's planning horizon for 138kV and lower voltage transmission facilities is about two years. The planning horizon for transmission facilities greater than 138kV is approximately five years. Kentucky Power currently has an application pending with the Commission for an interconnection, through a new substation (Wooten), with KU to enhance the reliability of service in the Hazard area of eastern Kentucky. An area reinforcement plan has been developed to establish new 138/69 kV transformer capacity at the Coalton Station to enhance the reliability of native load in the Ashland area. As previously noted, the Wyoming - Jacksons Ferry 765 kV line currently under construction will also address reliability concerns and benefit Kentucky Power's customers. Kentucky Power also noted that it may be necessary to further expand its transmission system if merchant facilities are located in its service area.[126]

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[124] Big River's Response to Staff's First Data Request, dated March 10, 2005, Item 22.

[125] East Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 22.

[126] Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 22.

KU's and LG&E's transmission planning horizon is generally ten years and is based solely on the need to deliver company-owned generator output and purchased generation to meet projected load. KU and LG&E identified 196 specific upgrades and additions. The projects include re-conductoring, thermal upgrades, installation of new line, replacement of old lines, impedance correction, new and replacement transformers, new switching and breaker replacement.[127]

The transmission expansion submitted for ULH&P for 2006 to 2007 consists of six projects. These projects primarily expand ULH&P's 69kV system by interconnecting with three new substations, Blackwell, Dry Ridge and Thomas Moore, which are being brought on-line to serve local load.[128]

Other Transmission Issues

New Technology

The delivery of power undergoes steady transformation, in materials, electronics, equipment, conductors, and software to manage the network. In many cases, the physical transmission lines remain in working order for decades and continue to serve the Kentucky customer, yet in order to continuously advance reliability concerns, utilities seek superior monitoring capabilities.

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[127] KU's and LG&E's Response to Staff's First Data Request, dated March 10, 2005, Item 22.

[128] ULH&P's Response to Staff's First Data Request, dated March 10, 2005, Item 22.

Big Rivers and it member distribution cooperatives are jointly purchasing GIS software and developing system data bases and data retrieval options. Big Rivers is also replacing its analog microwave equipment with a digital system.[129]

East Kentucky Power identified a number of new technologies it was considering for both transmission and distribution facilities. Some of the more significant are as follows:

East Kentucky Power utilizes Microprocessor Based Relaying, which is the use of computers and microprocessors in protective switchgear. These solid-state devices are virtually maintenance free, electronic devices which allow for additional functionality such as fault location algorithms, event recording, time stamping, and frequency monitoring. Fault current indicators decrease the time necessary to locate a fault after a transmission line has been sectionalized. Supervisory Control and Data Acquisition ("SCADA") Motor Operated Air Break Switches are remotely controlled switches which minimize the response time to outages and allow for automated line isolation renewal without crew involvement. The use of Light Detection and Ranging ("LiDAR") surveying allows the mapping and surveying of new transmission lines from helicopters via LASER and offers digital location information which can be utilized in other software applications. East Kentucky Power has also acquired Power Line Systems PLS-CADD which is the industry standard for transmission line design.[130]

[129] Big Rivers' Response to Staff's First Data Request, dated March 10, 2005, Item 2.

[130] East Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 2.

Kentucky Power is investigating lighter weight, non metallic conductors which allow for higher capacity transmission. In addition, it is evaluating fault current limiters, for safeguarding expensive plant. Kentucky Power is also implementing software which determines thermal loading capabilities along with remote cameras for determining Corona effect (the Corona effect is an undesired localized electronic discharge indicating possible hardware problems).[131]

KU and LG&E have installed current limiting reactors to redistribute 138 kV power flows and maximize resources. A second installation is underway that, when completed, will delay the need for new line construction for 7 years. KU and LG&E are using a CAD based design platform, Digital Terrain Models and LiDAR surveys to improve structure clearance accuracy and structural analysis of line support structures. A pilot program is in place that uses handheld GPS units and laptop computers for real time routing of transmission structures. A GIS system for transmission mapping is to be implemented in late 2005. KU and LG&E are partnering with another company to implement an GIS based line routing process. Finally, KU and LG&E are partnering with the FAA in a pilot program utilizing a new aerial obstruction marking system using radar to detect approaching aircraft.[132]

ULH&P is studying new composite core conductors which will allow for more reliable, higher capacity power delivery. ULH&P has reviewed devices that provide

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[131] Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 2.

[132] KU's and LG&E's Response to Staff's First Data Request, dated March 10, 2005, Item 2.

dynamic line ratings, automated meter reading, and innovative power line applications.[133]

Transmission Line Siting

The siting of facilities to be used for the transmission of electricity involves consideration of many issues, some of which are generally considered local in nature. These local issues include land-use management and planning and zoning. Electric utilities are required by Kentucky statute to construct facilities to provide adequate and continuous service to the public within their territories but KRS 100,324(1) exempts all service facilities to be located or relocated by a utility operating under the jurisdiction of this Commission or the FERC from local planning and zoning requirements.

Kentucky's jurisdictional utilities must obtain Commission approval before they construct any major transmission facilities. A 2004 amendment to KRS 278.020 authorized the Commission to regulate the construction of transmission lines that have a capacity of at least 138 kV and that are longer than 5,280 feet.

Non-jurisdictional entities that propose to build a transmission line with a capacity of at least 69kV must first receive a certificate from the Siting Board. The requirements of KRS 278.714 do not address need but do address siting issues such as the impact on Kentucky's scenic assets.

A few of the participants in the technical conference submitted comments relating to transmission siting issues. Most of the comments were along the lines of those submitted by East Kentucky Power that believes that the regulations governing transmission siting need to be reviewed and streamlined to eliminate uncertainty and

[133] ULH&P's Response to Staff's First Data Request, dated March 10, 2005, Item 2.

minimize costs.[134] Kentucky Power briefly discussed the problems one of its affiliates experienced when attempting to get a certificate for a major transmission line in another jurisdiction. As a result, Kentucky Power and AEP support vesting FERC with authority and eminent domain over siting in states "where transmission policy is not working." Kentucky Power believes that the policy is working in Kentucky.[135] ULH&P asks that both generation and transmission siting applications be processed in a manner that gives consideration to affected stakeholders but allows the facilities to be constructed promptly.[136]

MISO and PJM Activities

As previously noted, four Kentucky electric utilities are currently member of RTOs. As such, they participate in the regional planning activities of MISO or PJM.

The MISO transmission system spans 15 states and 1.2 million square miles. KU, LG&E and ULH&P, as an affiliate of Cinergy, are members of MISO. MISO is required by its charter to assess infrastructure needs on a regional basis and therefore may suggest state-based solutions or alternatives that may build upon initiatives being undertaken in other states within the Midwest. The key planning and reliability tool used by MISO is the MISO Transmission Expansion Plan ("MTEP"). The primary goal of the MTEP is to ensure the reliability of the transmission system under the operational and planning control of the MISO. In addition, the MTEP identifies transmission

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[134] Pre-filed comments of East Kentucky Power, dated June 8, 2005 at 8.

[135] Pre-filed comments of Kentucky Power, dated June 8, 2005 at 5 and Transcript at 20 and 34.

[136] Pre-filed comments of ULH&P, dated June 8, 2005 at 6.

expansion that is critical to support the competitive supply of electric power by this system.[137]

The current plan addresses 21 of the top 24 historical constraints contained within MISO's footprint, including three in Kentucky. Two of these constraints are in the Blue Lick area of the LG&E system and the third is the Paddy's – Summer 161 kV circuit in the LG&E and TVA systems.[138]

PJM serves as the FERC approved RTO in a thirteen state region that includes parts of eastern Kentucky. Kentucky Power, as an affiliate of AEP, is a member of PJM. One of the recent initiatives under exploration at PJM is "Project Mountaineer," an initiative to utilize a regional transmission planning process to explore ways to further develop an efficient transmission "super-highway" to bring low cost coal resources to market.

Project Mountaineer is also PJM's vision to make use of a robust transmission system to bolster economic development by moving power from the west to the east throughout the region, prompted by a resurgence in coal resource development and utilization. At this point, it should not be considered a proposal for any specific transmission line but a commitment to utilize a regional process involving Kentucky, the FERC, and the transmission owners, to explore new transmission opportunities to improve reliability and to enhance markets for Kentucky's low cost energy resources.[139]

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[137] Pre-filed comments of MISO, dated June 8, 2005.

[138] Id. at 4.

[139] Pre-filed comments of PJM, dated June 9, 2005 at 3.

Several of the participants in the technical conference submitted comments regarding their concerns about RTOs. The majority of those relate to the issue of jurisdiction and are addressed in the Barriers to Investment section. However, the comments of East Kentucky Power, KU and LG&E that described possible MISO operational issues are noted below.

East Kentucky Power discussed transmission constraints and the impact of those constraints on its ability to economically dispatch its generation. According to East Kentucky Power, its operators, at times, have been required to redispatch units, which has resulted in higher costs.[140] East Kentucky Power asked that Kentucky allow its utilities to join an RTO only if membership is found to be economically prudent.[141] Since joining MISO, KU and LG&E have raised numerous operational issues concerning MISO. They stated that their concerns were noted in a case pending before the Commission in which KU and LG&E have requested authorization to withdraw from MISO.[142]

Peabody Energy addressed transmission in its comments for the technical conference. Its concern relates to the need for enhancement of Kentucky's transmission infrastructure which Peabody Energy believes is relatively weak.[143] Peabody Energy set forth why Kentucky needs enhanced transmission: to continue

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[140] Transcript at 4.

[141] Pre-filed comments of East Kentucky Power, dated June 8, 2005 at 8 and 9.

[142] Case No 2004-000266, Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.

[143] Comments of Peabody Energy, dated June 20, 2005 at 3.

delivering affordable electricity for Kentucky families; to improve reliability for electricity throughout the Midwest; to enable new coal plants to be developed in Kentucky; and to increase coal production in Western Kentucky.[144] In support of its position, it states that Kentucky has only two north-south high voltage transmission lines, which tie into TVA, and only one-fourth as many miles of high voltage lines as Indiana.[145] While Peabody Energy supports Kentucky's plan to continue its use of coal-based generation to maintain its low-cost status, it believes that there are a number of generation and transmission projects that can strengthen Kentucky's electricity infrastructure and provide sound economic development opportunities.[146]

Resource Adequacy - Distribution

Electric distribution utilities provide electric service to end-use residential, commercial and industrial customers. Distribution facilities include power lines and facilities operating at voltages of less than 69 kV, and service line drops to customer meters.

There are three types of electric systems providing distribution service in Kentucky: rural electric distribution cooperatives, municipal utilities and investor-owned utilities. The majority of the distribution cooperatives (19) are jurisdictional and purchase their power from Big Rivers (3) or East Kentucky Power (16) which are commonly described as generation and transmission cooperatives. Currently, there are five non-jurisdictional distribution cooperatives operating in Kentucky that purchase their

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[144] Id., Attachment at 17.

[145] Id. at 3.

[146] Id.

power from TVA. The 30 municipal utilities which provide distribution service in Kentucky are not regulated by the Commission.

Distribution Resource Planning

Resource planning is conducted by the distribution systems to ensure reliable service at proper voltages is supplied to all customers.

The jurisdictional distribution cooperatives prepare long-range power requirements studies in conjunction with their service providers, Big Rivers or East Kentucky Power, which identify large growth patterns over an extended period. This expected growth is then combined with an analysis of the system performance during recent peak seasons to identify areas of the system which are in need of replacement or improvement. According to Blue Grass Energy Cooperative Corporation ("Blue Grass Energy"), this information is then used to create a two-, three- or four-year construction work plan which provides for new construction, line conversions, pole replacements, sectionalizing and other distribution resources.[147] The jurisdictional investor-owned electric utilities perform reviews of their distribution needs in conjunction with their integrated resource planning process. Their distribution plans are also based upon load forecasts and analysis of computer models.[148] As with generation resource planning, distribution planning is performed by the non-jurisdictional electric utilities in a manner similar to that of the jurisdictional companies.

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[147] Blue Grass Energy's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

[148] Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 1 and KU's and LG&E's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

New Distribution System Technologies

All of the distribution systems are evaluating or implementing new or advanced technologies to improve the reliability, efficiency or safety of their distribution facilities. The major types of new technologies that several of the distribution systems are either investing in or investigating are listed below:

- Automated GIS/Mapping Systems
- Automated Meter Reading
- Automatic Vehicle Locators
- Fault Indicators
- Infra-Red Cameras
- Outage Management Systems
- Supervisory Control and Data Acquisition Systems
- Work Order Programs

Other technologies that at least one distribution system identified as considering are:

- Broadband by Power Line (BPL)
- Call Center
- Composite Core Conductors
- Dynamic Line Rating
- Insulator Test Equip
- Lightning Arrestor Test Equip
- Maintenance Tracking
- Power Quality Monitor
- Underground Cable Locator

A brief description of the major new technologies follows:

Automated GIS/Mapping Systems. Many of the utilities have stated that they are investing in automated mapping or GIS systems. These systems allow the utilities to integrate their outage management systems, vehicle tracking systems, work order tracking systems, and call centers to enhance the effectiveness of their response to customer calls and service interruptions.

Automated Meter Reading. Automated Meter Reading ("AMR") allows the logging of consumption data to be used for future planning, remote detection of potential problems, and the possible operation of remote devices for circuit isolation and the reduction of outages and their duration. AMR eliminates the need for employees to travel to and read each meter monthly for accurate customer billing. AMR readings allow data integration with accounting and billing systems to be seamless and all electronic. An AMR system can monitor outages, blinks and voltage swings at the customer location and possibly permit remote connections and disconnections. AMR can result in cost savings by reducing labor, vehicle acquisition and maintenance, and improved engineering efficiencies.

Automatic Vehicle Locators. Automatic vehicle locator ("AVL") is a tracking system for service trucks. AVL tracking allows the utility dispatcher to view the locations of all service trucks and route the closest available truck to an outage or high priority job.

Fault Indicators. Fault Indicators provide information back to the utility regarding momentary faults on a distribution system. This could be an indication of a transient fault caused by animal contact or a tree branch, or it could indicate a problem with distribution equipment.

Infra-Red Cameras. Infrared cameras are used to check the operating temperature of distribution equipment. Areas of high temperature indicate potential problems which can then be further investigated and corrected before an outage occurs.

Outage Management Systems. Outage management systems ("OMS") provide employees with information needed in the restoration of service interrupted by storms and allow the utility to organize the outage information collected by telephone, by local employees, or by contract call centers. An OMS predicts possible distribution system device tripping such as reclosers or substation breakers.

Supervisory Control and Data Acquisition. SCADA systems provide real-time acquisition of data from each substation, including station output voltage, breaker status, power factor and the operating status of individual feeders. In addition, SCADA systems allow for remote control of feeder breakers and voltage regulators.

Work Order Programs. Work order programs allow the dispatcher to dynamically assign crews to high priority jobs while they are in the field. They can then reassign any necessary work order to balance the work load without having to wait for crews to return to the dispatch office.

Only one utility, ULH&P, identified Broadband by Power Line as a new technology being investigated. This technology allows consumers to use electric power conductors as access to the Internet. It also provides the utility with a means to communicate with all its power distribution equipment.

Distribution System Reliability

Reliability can be thought of as the probability of power being supplied to a load when it is required. It can also be defined in the converse as the likelihood of power not being supplied when it is demanded. According to the U.S. Department of Energy ("DOE") when referring to an electric system, reliability is the measure of the ability of the system to operate when some lines or generators are out of service and that reliability deals with the performance of the system under stress. There are a number of ways to measure distribution system reliability, however, and several standard indices have been created for this purpose.[149] Most of the jurisdictional electric distribution systems have adopted SAIFI, SAIDI, and CAIDI as their preferred indices although

[149] The Institute of Electrical and Electronics Engineers, Inc, IEEEP1366™/D14, July 2003.

other factors are also tracked.[150] SAIFI indicates how often a customer experiences a sustained (more than 5 minutes) service interruption, SAIDI measures the duration of interruption for an average customer, and CAIDI represents the average time required to restore service. In general, these three indices measure the likelihood of power not being available when it is demanded.

Although the jurisdictional utilities provided the SAIFI, SAIDI and CAIDI numbers as requested, a comparison of the indices among the utilities is impractical for several reasons. Because major events such as a tornado, ice storm, or a hurricane can have a large impact on the reliability indices and make an otherwise good system appear to be operating poorly, such events are generally excluded from the calculation of the index. There is no single industry standard defining major events; therefore, the electric utilities do not follow the same criteria for defining a major event.[151]

In addition, there were inconsistencies in the level of detail in the data. Some utilities provided reliability data only on a system-wide basis while others provided information by regional division of the utility, by sub-station or by circuit feeder. The size of the unit used to determine the reliability index has a large impact on the variability of the indices. Small units (feeders) will have the greatest variability while large units (system-wide) may be relatively equal. Also, the fact that some utilities reported the length of an outage by minutes and others reported it by hours makes comparison of the duration data difficult.

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[150] Based on Staff's Analysis of Responses to Staff's First Data Request, dated March 10, 2005, Item 31.

[151] Id., Item 27.

The jurisdictional electric utilities were asked to provide acceptable SAIDI, SAIFI and CAIDI indices value for their systems. Of the 21 utilities responding, only four had established values for target reliability indices. Kentucky Power uses a statistical review of the previous year's performance at each feeder and then establishes the mean plus one standard deviation as the goal for SAIFI, SAIDI, and CAIDI for the next year.[152] Clark Energy has established a SAIDI value of 5 as its target.[153] Both Salt River Electric and Shelby Energy Cooperative have based their goals on published industry standards for system-wide indices.[154] Many responded as did KU and LG&E stating that the indices may vary greatly and would be meaningful only if reviewed over time.[155]

Power Disruption Causes

The utilities were also asked to provide the number and causes of reportable outages. A reportable outage is defined by 807 KAR 5:006, Section 26(1)(c) as "loss of service for four (4) or more hours to ten (10) percent or 500 or more of the utility's customers, whichever is less." Fifteen of the responses included reportable outages while six of the responses included data on all outages.[156]

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[152] Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Items 29 and 30.

[153] Clark Energy's Response to Staff's First Data Request, dated March 10, 2005, Items 29 and 30.

[154] Salt River Electric's Response to Staff's First Data Request, dated March 10, 2005, Items 28 and 29 and Shelby Energy Cooperative's Response to Staff's First Data Request, dated March 10, 2005, Items 28 and 29.

[155] KU's and LG&E's Response to Staff's First Data Request, dated March 10, 2005, Items 28 and 29.

[156] Based on Staff's Analysis of Responses to Staff's First Data Request, dated March 10, 2005, Item 30.

Based on the information provided, the major cause for reportable outages was weather related (wind and ice), followed by vehicle accidents, equipment failure and vandalism. The five major reasons for outages of each company that provided information on all outages are shown below:[157]

Summary of Major Reportable Outages

Rank	Kentucky Power	Cumberland Valley Electric	Kenergy	Meade RECC	Nolin RECC	Owen Electric
1	Tree in ROW	Equip Failed	Supplier	Storms	Lightning	Weather
2	Equip Failed	Trees	Overhead Equip Fail	Animals	Trees	Unknown
3	Tree out ROW	Animals	Animal	Other	Unknown	Equip Failed
4	Animal	Accident	Lightning	Trans. Failed	Weather	Animals
5	Lightning	Storm	Conductor Failed 2ACSR	Tree out ROW	Major Storm	Member/Public

Reliability Improvement Program

As noted above, the electric utilities responded that in addition to SAIDI, SAIFI and CAIDI, they also track and measure distribution reliability through other means. Generally, the utilities analyze system outage reports, get direct feedback from operations and engineering personnel, and use event recorders at each of the utility substations. Repeated events (oil circuit recloser operations, blown fuses) are investigated and specifically targeted for corrective action. Corrective action could include tree trimming, protective device maintenance, and repair or full scale conductor replacement.[158]

[157] Id., Item 30.

[158] Id., Item 31.

KU and LG&E, for example, stated that they have created a centralized reliability engineering group to coordinate reliability improvement initiatives. KU and LG&E monitor their monthly outage reports and have started to use reliability indices to manage their reliability performance. By reviewing the hardest hit areas, KU has been able to reduce its tree-related SAIFI by 13 percent and tree-related SAIDI by 20 percent from 2003 to 2004 while LG&E has been able to reduce its tree-related SAIFI by 67 percent and tree-related SAIDI by 48 percent during the same time frame.[159] During 2004, KU and LG&E also implemented an OMS to provide improved data collection and reporting.[160] ULH&P encourages reliability improvement by including the indices as part of the performance review for key personnel. In addition, ULH&P reviews the feeders and local situations with higher outage frequency and in 2005 added a program to assist in this review.[161]

In general, the utilities provided useful information; however, the information provided indicated that reliability was not tracked through standard indices. Likewise, the utilities did not provide concrete results of their programs.

Distribution Right-of-Way and Vegetation Management

The electric utilities have right-of-way ("ROW") maintenance and vegetation management programs to minimize tree-related outages. These programs also contribute to more rapid storm-related restoration by improving accessibility to lines

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[159] KU's and LG&E's Response to Staff's First Data Request, dated March 10, 2005, Item 31.

[160] Id.

[161] ULH&P's Response to Staff's First Data Request, dated March 10, 2005, Item 31.

during emergency conditions. Responses show the utilities employ cycles ranging from three to eight years to schedule the clearing program with a five-year cycle being typical. The table below shows the combined ROW maintenance and vegetation management expense for most of the jurisdictional utilities and two of the TVA distribution cooperatives for the years 2002 through 2004.[162]

Annual Right-Of-Way And Vegetation Management Expense[163]

	2002	2003	2004	Average
Investor Owned Utilities				
Kentucky Power	$4,270,641	$4,408,009	$7,208,035	$5,295,562
Kentucky Utilities	$6,835,000	$5,906,000	$9,673,000	$7,471,333
LG&E	$3,215,000	$2,629,000	$3,520,000	$3,121,333
ULH&P	$2,109,010	$2,615,477	$4,205,811	$2,976,766
Jurisdictional RECCs				
Big Sandy RECC	$ 269,000	$ 359,000	$ 562,000	$ 396,667
Blue Grass ECC	$1,727,046	$2,485,140	$2,132,667	$2,114,951
Clark Energy	$ 983,245	$1,073,998	$1,017,420	$1,024,888
Cumberland Valley Electric	$ 769,999	$ 877,453	$ 899,993	$ 849,148
Farmers RECC	$ 600,167	$ 698,498	$ 747,523	$ 682,063
Fleming-Mason Energy	$1,118,737	$1,215,108	$1,182,270	$1,172,038
Grayson RECC	$ 750,780	$ 684,559	$ 771,015	$ 735,451
Inter-County Energy	$ 565,000	$ 550,000	$ 620,000	$ 578,333
Jackson Energy	$1,877,851	$2,205,257	$2,359,195	$2,147,434
Jackson Purchase Energy	$ 486,911	$ 700,000	$ 647,900	$ 611,604
Kenergy	$ 748,375	$1,324,652	$2,313,971	$1,462,333
Licking Valley RECC	$ 523,763	$ 415,321	$ 383,879	$ 440,985
Meade County RECC	$ 534,041	$ 787,174	$ 800,378	$ 707,198
Owen EC	$1,192,500	$1,316,500	$1,300,000	$1,269,667
Pennyrile Electric	$ 825,00	$ 813,000	$ 895,000	$ 844,333
Salt River Electric	$ 749,000	$ 910,000	$ 875,000	$ 844,667
Shelby Energy	$ 449,163	$ 456,068	$ 526,501	$ 477,244
TVA Supplied RECCs				
South Kentucky RECC	$1,694,525	$2,408,232	$1,660,023	$1,920,927
Warren RECC	$1,347,108	$1,364,315	$2,174,660	$1,628,694

[162] Based on Staff's Analysis of Responses to Staff's First Data Request, dated March 10, 2005, Item 32.

[163] Based on Staff's Analysis of Responses to Staff's First Data Request, dated March 10, 2005, Item 32.

Pole and Conductor Replacement Criteria

The electric utilities provided the criteria they use to determine the need for replacement and improvement of existing distribution plant facilities. The major criteria are listed below: [164]

Observations from field operations personnel.

Annual Ground and Aerial Patrol Reports.

Analyses of outage records and annual operations and maintenance reviews, particularly for conductors with more than three outages or more than 10 outage hours in two of the last three years.

Conductors with excessive splicing, more than one splice per span per phase for any given mile, are replaced.

Results from Biennial Visual Inspection of all Facilities.

Utility poles are sounded and/or bored on a two- to 10-year cycle to check for rot.

Utility poles are replaced or reinforced if the loading on the pole exceeds its designed capacity.

Conductors are replaced if the thermal loading exceeds 75 percent of rating.

The utilities also responded that typically pole replacement projects are evaluated so that a balance is struck as much as possible between the degree of reliability enhancement and dollars spent.

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[164] Based on Staff's Analysis of Responses to Staff's First Data Request, dated March 10, 2005, Item 33.

Other Distribution System Related Issues

Pre-filed and oral comments were provided by Meade County RECC on behalf of the electric distribution cooperatives. Meade County RECC identified the Kentucky Revenue Department's decision to assess sales tax on distribution and substation transformers, which had historically been tax exempt, as an issue the Commission should consider in developing the "strategic blueprint." The cooperatives are concerned with the negative impact such a decision will have on the price of electricity. As did the generation and transmission utilities, Meade County RECC cited the cost of fuel, the cost of environmental compliance, the cost of future generation, and transmission siting as major issues facing the electric industry. Finally, Meade County RECC cited the following potential barriers: (1) regulatory equity between jurisdictional and non-jurisdictional electric providers; (2) the ability to break power requirements contracts; (3) the increasing cost and complexity of obtaining Commission approval of construction work plans; and (4) the need that RUS funding remain available to distribution cooperatives.[165]

Energy Efficiency, Demand-Side Management and Conservation

The regulated utilities were asked to respond to questions regarding the efficient use of energy, conservation and demand-side management ("DSM"). In addition, these issues were also addressed in written and narrative comments by some technical conference participants.

As part of their IRP filings made pursuant to 807 KAR 5:058, the six major jurisdictional electric utilities, Big Rivers, East Kentucky Power, Kentucky Power, KU,

[165] Pre-filed Comments of Meade Co. RECC, dated June 8, 2005.

LG&E, and ULH&P, must evaluate DSM resources in conjunction with their evaluation of generation resources as part of their plans for meeting their customers' future electric demands. Their responses filed in this proceeding largely reflect their current DSM programs and their approach to selecting and implementing DSM measures as well as conservation programs.

Big Rivers

Big Rivers stated that it performs appropriate cost/benefit analyses to determine acceptable DSM measures to initiate.[166] It provides financial and technical support for the DSM offerings of its three distribution cooperatives. The programs available through Big Rivers are:

- Add-on heat pump – an incentive of $90 per ton of capacity when replacing an air conditioning system with a heat pump.
- All Electric Touchstone Energy Home – an incentive of between $225 and $265 is available for heat-pump installation, depending on type, if a new home is located within 1,200 feet of a natural gas distribution line.
- Electric water heater – an incentive of $300 is if fossil fuel water heater is replaced with an electric water heater.[167]

Big Rivers also provides other DSM-related programs and certain residential, commercial and industrial energy efficiency services through its distribution cooperatives. These services are:

- Energy Efficiency and Safety Workshops – educational workshops.
- Energy-Use Assessment – an energy audit to identify opportunities to improve efficiency and lower energy costs.

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[166] Big Rivers' Response to Staff's First Data Request, dated March 10, 2005, Item 1.

[167] Id., Item 17 at 1.

- Operation Assessment – an evaluation of how a member uses energy.

- Customer Billing Review – an explanation of billing documents and rate structures.

- Commercial Lighting Evaluation – an evaluation of facility and security lighting.

- Power Factor Correction Assistance – a program aimed at correcting low power factors.

- Power Quality Assessment – a review of equipment damage or productivity losses as a result of power quality problems.

- Energy Use Summary – a Web site-based comparative summary of energy use, billing data and weather date.

- Customized Billing Services – the ability to send multiple bills in the same mailing.

- Residential energy auditing – the provision of residential energy audits and Energy Star rating for new construction.

- Weyerhaeuser Generation – Big Rivers worked with the paper plant to allow it to construct a generator and use bio-mass and waste steam to generate part of its electrical needs. This reduced Big Rivers' demand by 50 MW.[168]

East Kentucky Power

When evaluating its capacity needs, East Kentucky Power performs a screening analysis of capacity alternatives including DSM.[169] Most of the DSM programs East Kentucky Power offers through its member systems are residential programs which

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[168] Id., Item 17 at 2-5.

[169] East Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

involve HVAC or water heating efficiency measures. A listing of the available programs with a brief description is shown below:

- Button Up Weatherization Program – an incentive of up to $400 is provided for installation of insulation or other weatherization techniques to reduce heat loss.

- Air-Source Heat Pump Incentive – the promotion of the use of air-source heat pumps in new homes where natural gas heat is an option or to replace gas or propane furnaces with electric heat pumps.

- Electric Thermal Storage – bricks heated during off-peak hours provide heat during on-peak hours. A time-of-day rate applies to this program.

- Electric Water Heater Incentive – an incentive of $100 is provided to encourage the installation of high-efficiency electric water heaters over available alternatives in new residential construction.

- Geothermal Heating and Cooling – an incentive of $300 is provided to encourage the installation of geothermal heat pumps that remove heat from the ground over available alternatives.

- Touchstone Energy Home – an incentive to construct new homes to Touchstone Energy specifications.

- Tune Up HVAC Maintenance – cleaning indoor and outdoor HVAC related equipment to improve efficiency.[170]

The non-residential DSM program offered by East Kentucky Power promotes interruptible rate pricing as a DSM tool. One customer with 124 MW of interruptible demand accounts for most of the interruptible demand on the system.[171]

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[170] Id., Item 17 at 1 through 6.

[171] Id., Item 17 at 1.

Kentucky Power

In its review of available future resource options, Kentucky Power includes a review of demand-side resources. Kentucky Power states that its DSM planning parallels its capacity resource planning process where it follows the following steps:

- Establish a DSM measure database.
- Carry out preliminary screening and packaging.
- Analyze system cost-benefit.
- Combine with supply-side analysis.
- Analyze participant cost-benefit.
- Implement DSM
- Follow-up and verify[172]

A summary of Kentucky Power's current DSM programs is shown below:

- Targeted Energy Efficiency Program – provides energy audits, consultation, and installation of weatherization, and conservation measures for eligible low-income customers in conjunction with certain not-for-profit agencies.

- High Efficiency heat pump mobile home program – provides a $400 incentive to mobile home customers that replace their resistant heat system with a high-efficiency heat pump.

- Mobile home new construction program – provides a $500 incentive to buyers who purchase a new mobile home with specific insulation levels. An additional $125 incentive is available to new mobile homes that also include a 12 SEER air conditioner.

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[172] Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

- Modified energy fitness program – a program to encourage residential customers to have an energy audit and install appropriate energy saving measures.[173]

KU and LG&E

As is the case with the other jurisdictional generating utilities, KU and LG&E conduct a screening analysis of DSM options as part of their IRP process.[174]

A summary of the DSM programs offered by KU and LG&E is shown below:

- Residential Energy Audits – identifies opportunities for improving energy efficiency for single-family homes, apartments or condominiums. Below-market financing for Energy Star appliances is also available.

- Commercial Energy Audits – identifies opportunities for improving energy efficiency but for commercial customers. Below-market financing for Energy Star appliances is available under this program.

- Demand Conservation Program - cycles residential and commercial central air conditioning units, water heaters, and residential pool pumps when KU and LG&E need additional resources to meet customer load.

- We Care Program – a weatherization program available to LIHEAP eligible customers.[175]

ULH&P

ULH&P also conducts DSM planning as part of its IRP. Initially, potential programs are identified through a market potential analysis conducted by external

[173] Id., Item 17.

[174] KU's and LG&E's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

[175] Id., Item 17.

consultants. Cost-effective DSM programs are implemented subject to agreement of ULH&P's DSM collaborative and Commission approval.[176]

A description of ULH&P's currently available DSM programs is provided below:

- Residential Conservation and Energy Education (Low-Income Weatherization) – provides for the installation of weatherization and other energy saving measures for LIHEAP eligible customers.

- Refrigerators – replaces poor performing refrigerators with Energy Star units.

- Residential Home Energy House Call – provides for an energy survey, an energy audit, and installation of certain energy saving measures at no cost.

- Residential Comprehensive Energy Education (NEED) – provides education materials, other related info, and energy savings kits to teachers.

- Pilot Program: Energy Education and Bill Assistance (Payment Plus) – provides energy and budget workshops, home weatherization and bill assistance credits.

- Power Manager (Residential) – allows ULH&P to control residential air conditioners during peak demand conditions.

- Energy Star Products (Residential) – provides incentives to purchase and use certain Energy Star products.

- Energy Efficiency Website – provides energy saving information allows customers to complete on-line audits and provides customers with an Energy Efficiency Starter Kit.

- High Efficiency Incentive (Commercial and Industrial) – provides incentive to small commercial and industrial customers to install or retrofit with certain high efficiency equipment.[177]

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[176] ULH&P's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

[177] Id., Item 17.

TVA

TVA provided information on its DSM menu with the explanation that not all member systems offered all programs. A summary of TVA's programs is shown below:

- New Homes Plan – promotes all electric, energy efficient homes.
- Heat Pump Plan – promotes the installation of high efficiency heat pumps of 12 SEER or greater.
- Water Heater Plan – promotes the installation of energy efficient electric water heaters.
- New Manufactured Home Plan – promotes the installation of energy efficient electric heat pumps in new manufactured homes.
- In Concert with the Environment – an education program for middle and junior high school.
- Energy Right Home-Valuation – provides an online energy audit for residential customers.
- Direct Load Control – allows utilities to curtail power to air conditioners and water heaters during peak hours.
- Also works with commercial and industrial customers to help provide solutions to energy related problems.[178]

Non-Utility Participants

Although its comments were more focused on the impact of externalities and the promotion of greater development of renewables, the KRC stated that Kentucky lagged behind others in end-use energy conservation.[179] It contends that end-use conservation measures (as well as renewables) are currently available but underutilized due to the incentives for constructing coal-fired generating plants and by not properly accounting

[178] TVA's Response to Staff's First Data Request, dated March 10, 2005, Item 1.

[179] Pre-filed statement of Thomas J. Fitzgerald, Director, Kentucky Resources Council, Inc. at 5.

for related externalities.[180] Greater investment in energy conservation is necessary to curb pollution and control the rate of energy consumption, the KRC argues.

The focus of ESG's comments related to energy conservation. Several studies were supplied to support its position that rising fuel costs, increased environmental standards and other externalities will increase the cost of future electric production; therefore, the electric power industry is in need of renewal, according to ESG. It notes that a barrier to future investment in energy efficient products is a lack of perception regarding "alternatives to supply side solutions, and the economic potential alternatives offer."[181] ESG argues that the power infrastructure should focus on energy conservation with an increased role for DSM options. ESG argues that conservation measures typically cost 2 to 3 cents per Kwh saved and are below the cost of new production. ESG points out various energy conservation technologies available for DSM programs that ESG believes are underutilized in Kentucky.

Finally, ESG argues that Kentucky needs a stronger DSM program to keep its low rates and competitive edge. ESG believes the program should be designed to create business opportunities for energy engineers, energy managers, alternative energy production companies and energy service companies. Initiatives that should be considered include:

- Adoption of the International Building Energy Code
- Adoption of standards using green construction practices and related incentives
- Adoption of the Energy Star program

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[180] Id. at 15-6.

[181] Pre-filed Comments of ESG, dated June 3, 2005 at 2.

- Utility funded incentives for DSM
- Funding for energy conservation research centers
- Utility surcharges to subsidize rebates for energy savings products

According to ESG, implementing these policies will help keep and create high-paying technology jobs while allowing continued industrial expansion. ESG also states that this greater focus on DSM will reduce the need to improve the transmission infrastructure.[182]

Geoff Young also provided comments on DSM and improving energy efficiency. Mr. Young notes that the key point made by ESG was that the largest energy source in the U.S. over the last 15 years has been improved energy efficiency. While agreeing with ESG that Kentucky has not taken advantage of this pollution free energy source, Mr. Young broadens the focus of his comments to the idea of "whole-system design."[183] This system incorporates construction design, design of the manufacturing process, etc. in combination with energy efficiency products and measures to reduce energy demand. Mr. Young also cites other DSM and energy efficient measures and products available.

Donald Colliver, Ph.D., P.E., appearing as a private citizen, provided written comments and also offered comments at the technical conference. Dr. Colliver noted that Kentucky has low electricity prices but that its energy usage is among the highest in the nation which results in high energy bills.[184] As a result of his work and experience, Dr. Colliver cited the amount of energy used in buildings including residences, small

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[182] Id. at 2 and 3.

[183] Comments of Geoff Young, dated June 20, 2005 at 2.

[184] Comments of Dr. Donald Colliver, dated June 13, 2005 at 1.

office and retail buildings, and schools. Dr. Colliver cited the development of building energy codes in new homes and commercial buildings and the use of energy efficient technology in new construction as the major ways to reduce energy consumption. Some energy savings can be accomplished from retrofits in existing buildings but the impact is will not be as great as in new construction, according to Dr. Colliver.[185]

Renewable Resources and Alternative Generation Technology

Renewable Resources

According to the Federal Government's Energy Information Administration's ("EIA") Energy Glossary, renewable energy resources ("Renewables") are defined as "Energy resources that are naturally replenishing but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Renewable energy resources include: biomass, hydro, geothermal, solar, wind, ocean thermal, wave action, and tidal action."[186] Each of the jurisdictional utilities was asked about research into renewable fuels. The responses were mixed.

Big Rivers stated that it has leased its generating units to WKE and that since its power is now furnished through purchases it did not have control over fuel selection. However, Big Rivers did note that it "has cooperated with a paper mill to facilitate its generation of power from biomass, and is investigating sources from which it can purchase small amounts of 'Green Power.'"[187]

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[185] Id. at 2 to 4.

[186] Energy Information Administration, Energy Glossary, R at 8 to 9.

[187] Big Rivers' Response to Staff's First Data Request, dated March 10, 2005, Item 3.

In its response to data requests, East Kentucky Power stated that, after completing a positive evaluation about three years ago regarding the use of landfill produced methane gas to generate electricity, it had received approval for three such generating plants that were constructed in 2003.[188] East Kentucky Power is also seeking to construct a fourth plant in Hardin County.[189] East Kentucky Power stated that it is studying generating electricity from methane recovered from certain industrial waste processes as well as wind. East Kentucky Power stated that economies of scale presented an obstacle and that it is challenging to develop a small-scale renewable project that will be competitive with base load coal units of 200 or 300 MWs. In addition, East Kentucky Power noted that, due to its low capacity factor, Kentucky's wind resource, may not be competitive on a cost per kwh. Finally, East Kentucky Power identified view-shed issues, noise pollution and avian risks that also posed obstacles.[190] In its comments for the technical conference, East Kentucky Power noted that deployment of clean coal technology and renewables can have a beneficial impact and are a key to Kentucky's future.[191] East Kentucky Power identified circulating fluidized bed (which is the technology to be utilized by three plants proposed by East Kentucky

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[188] East Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 3.

[189] Case No. 2005-00164, Application of East Kentucky Power Cooperative, Inc. for an Order Declaring the Hardin County Landfill Gas to Energy Project to be an Ordinary Extension of the Existing Systems in the Usual Course of Business, filed April 22, 2005

[190] East Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 3.

[191] Pre-filed Comments of East Kentucky Power, dated June 8, 2005 at 5 and Transcript of Technical Conference ("Transcript"), dated June 14, 2005 at 12.

Power) and IGCC as two clean coal technologies. East Kentucky Power noted that IGCC technology was technically sound but faced capital and operating cost issues.[192] As a result, East Kentucky Power recommended that Kentucky provide initiatives to research and mitigate those uncertainties. East Kentucky Power suggested that seed capital could be provided for utilities to partner with industry or that financial support to offset the premium cost of IGCCs could be provided by using revenue bonds retired by severance taxes from the IGCC projects.[193]

ULH&P stated that it was researching wind, solar, and biomass but that the main obstacle was that they are not cost-effective on a utility scale.[194]

Kentucky Power stated that it was not researching renewables but it reported on the activity of AEP and other affiliates. AEP companies own two wind farms with 310 MWs of generating capacity and are involved in a third 75 MW project, all in Texas. Kentucky Power also noted that AEP generated approximately 870 MWs of electricity from 17 hydroelectric plants. Finally, Kentucky Power discussed AEP's research into biomass. It noted that a test burn of biomass had recently been completed at an affiliate's plant in Ohio. The product tested consisted of co-firing up to 20 percent wood chips with coal. A feasibility study is currently being conducted for co-firing biomass (wood chips) at another plant in Ohio and with the goal of testing the use of biomass (wood chips) at the cyclone-fired boilers there. Finally, Kentucky Power stated that AEP was conducting biomass assessment surveys throughout the Eastern states to

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[192] Id.

[193] Pre-filed Comments of East Kentucky Power, dated June 8, 2005 at 5 and 6.

[194] ULH&P's Response to Staff's First Data Request, dated March 10, 2005, Item 3.

determine the quantity and availability of biomass that can be used for co-firing in its boilers.[195]

Among the obstacles noted by Kentucky Power were the environmental restrictions for new hydroelectric facilities, the relatively high capital cost and low capacity factor for wind power and the economic challenges of co-firing biomass.[196] In addition, Kentucky Power noted that developing clean coal power plants due to the probable retirement of older units should be a top priority.[197]

KU and LG&E stated that they performed a supply-side screening which looked at several renewable fuels as part of the IRP process. They stated that wind power was not a viable resource nor was solar power. With the exception of hydro, none of the remaining renewable options passed their screening.[198]

Regarding the use of renewables, TVA provided a brief discussion of its Green Power Switch ("GPS") program which includes electricity generated from wind, solar and methane gas.[199] TVA also indicated that it was investigating the use of biodiesel fueled generation for distributed generation.[200] Bowling Green Municipal Utilities

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[195] Kentucky Power's response to Staff's First Data Request, dated March 10, 2005, Item 3.

[196] Id.

[197] Pre-filed Comments of Kentucky Power, dated June 8, 2005 at 2.

[198] KU's and LG&E's response to Staff's First Data Request, dated March 10, 2005, Item 3.

[199] TVA's response to Staff's First Data Request, dated March 10, 2005, Item 1.

[200] Id., Item 3.

("BGMU"), a TVA supplied utility, stated its support for GPS and also noted its support of customer owned solar generated net-metered power.[201]

At the June 14, 2005 Technical Conference, several participants briefly discussed renewables, among other things, in their narrative and written comments. As previously noted, the KRC stated that Kentucky "lagged behind many parts of the nation in the development of potential renewable resources, and end-use energy conservation."[202] The KRC further stated that end-use conservation and renewables were available at competitive prices but ignored by the utilities. The KRC rather directly implies that this is due to the numerous incentives available for fossil fuel production and the failure to properly include the price of externalities in the fuel equation. As an example, the KRC cites the availability of Ohio River hydroelectric power that it claims the utilities don't want.[203] Finally, the KRC argues that there is a move in Washington for a national renewable portfolio and because of carbon dioxide ("CO_2") emissions there will be a significant impact to Kentucky.[204]

Moore Environmental appeared individually at the technical conference and submitted written comments after the conference. Moore Environmental's comments also support the use of renewable technology; however, the focus of its comments is directed toward the use of "rapid growth woody perennials"[205] for co-firing. Moore

[201] BGMU's Response to Staff's First Data Request, dated March 10, 2005, Item 3.

[202] Pre-filed comments of KRC, dated June 8, 2005 at 5.

[203] Id. at 6 through 16.

[204] Id. at 16.

[205] Comments of Moore Environmental, dated June 22, 2005 at 1.

Environmental states that the benefits of retrofitting existing generating units and requiring that the technology (to co-fire woody perennials) be included in future plant design are "multifaceted and quantifiable and requests that the use of woody perennials be mandated."[206] Moore Environmental states that without such a mandate the technology for co-firing rapid growth woody perennial "will lack priority".[207] However, other than implying that there are economic development benefits for agriculture and citing other externalities, no benefits were identified nor did Moore Environmental reference any studies supporting the use of renewables.

Beyond co-firing rapid growth woody perennials, Moore Environmental asks that cogeneration be mandated for industry, that a partnership with Wyoming trading wood fired-power for wind and solar generated power be mandated, and that an environmental accounting statement be mandated. Moore Environmental also asks that the use of renewables be mandated to participate in a carbon trading market. Finally, Moore Environmental states that the failure to mandate biomass co-firing will "translate directly into lost opportunity for Kentucky farmers and will far exceed the benefit of interim investment strategy."[208]

Dr. Colliver also stated that energy savings could be achieved in new and existing buildings by the use of renewable energy.[209]

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[206] Id.

[207] Id.

[208] Id. at 2 and 3.

[209] Pre-filed Comments of Dr. Donald Colliver, dated June 13, 2005 at 3.

Alternative Generation Technology

Each of the jurisdictional generation and transmission utilities was asked about the use of alternative generation technology. Their responses are discussed below:

As it did regarding renewables, Big Rivers' responded that it had not considered alternative generation technology since its generating plants are leased to LG&E Energy and operated by WKE and, as such, it does not have control over what new technologies are investigated or considered for power generation.[210]

East Kentucky Power stated that, since it selects the of capacity additions to be made through an RFP process, it has no control over what technology bidders may offer. East Kentucky Power did indicate that, under certain circumstances, new technologies may be considered as self-build options. According to East Kentucky Power, the CFB boiler technology used in the new Gilbert Unit is relatively new technology for coal-fired generation and it plans to use that same technology for at least two more units. Also, as noted elsewhere, East Kentucky Power has three landfill gas generation projects in commercial operation with another in development. Finally, East Kentucky Power indicated that it planned to implement GE's new high efficiency combustion turbine technology in 2007 and that it had studied hydro-matrix technology.[211]

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[210] Big Rivers' Response to Staff's First Data Request, dated March 10, 2005, Item 2.

[211] East Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 2.

Kentucky Power responded that AEP is investigating new technologies to improve reliability, efficiency and/or safety. According to Kentucky Power, AEP has been working with Battelle and the US Department of Energy to assess the geologic formations at the Mountaineer Plant on the Ohio River which, while not operational, is providing information regarding sequestration of CO_2. AEP has also evaluated IGCC technology which is being considered for a site in Lewis County, Kentucky. AEP has also investigated the use of a number of new technologies to aid in the management of its generation assets. And, as noted above, AEP has researched biomass co-firing and wind turbines.[212]

In term of new technologies for generation, KU and LG&E described technologies that had been reviewed and implemented to improve the reliability, efficiency and safety of their generation fleet.[213] New generation technology is screened as part of the IRP process and considered if included as a response to RFPs issued for additional generation.

ULH&P briefly noted new technologies that are considered in Cinergy's planning processes. In addition to subcritical and supercritical pulverized coal units, fluidized bed units, advanced CTs and CCs, IGCC units, fuel cells, wind turbines, solar, biomass, and storage units have been reviewed but not implemented. According to ULH&P, Cinergy,

[212] Kentucky Power's Response to Staff's First Data Request, dated March 10, 2005, Item 2.

[213] KU's and LG&E's Response to Staff's First Data Request, dated March 10, 2005, Item 2.

GE and Bechtel are currently performing a detailed study of the potential construction of an IGCC unit.[214]

Other than TVA and BGMU in their discussion of renewables, none of the non-jurisdictional utilities provided any information regarding new generation technology.

Some of Kentucky's Pioneer's comments regarding new technology have been noted in the Merchant Plant section as they were pertinent to issues relating to merchant plants. However, Kentucky Pioneer also recommended that coal gasification, an alternative generation technology, be studied for the development of a Strategic Blueprint, particularly IGCC technology.[215] In its comments, Kentucky Pioneer describes the IGCC process and explains the advantages of IGCC units. According to a study provided by Kentucky Pioneer, IGCCs can burn coal more cleanly than current base load technology thereby producing fewer noxious emissions.[216] The most important aspect of this benefit is the ability of IGCCs to sequester carbon emissions. In addition, the greater use of IGCCs to burn coal will also reduce the reliance on natural gas for electricity generation. The study also identifies a benefit to national security because the coal supply chain is predominantly domestic rather than international and is less vulnerable to sabotage.[217] However, the study also identifies

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[214] ULH&P's Response to Staff's First Data Request, dated March 10, 2005, Item 2.

[215] Pre-filed Comments of Kentucky Pioneer, dated June 8, 2005 at 1.

[216] An Analysis of the Institutional Challenges to Commercialization and Deployment of IGCC Technology in the U.S. Electric Industry: Recommended Policy, Regulatory, Executive and Legislative Initiatives by Dr. John O'Brien, Joel Blau and Mathew Rose, Global Change Associates, March 2004, Executive Summary at ES-1 and ES-2.

[217] Id.

important challenges to IGCC deployment. Chief among these are higher capital costs and unproven reliability which results in uncertainty regarding the ability to finance such projects.[218]

KIUC stated that it did not see IGCC as an answer to meeting environmental requirements and maintain low rates unless there were significant federal incentives.[219] In its pre-filed comments, KIUC did not see the need for any new rate mechanism for cost recovery of an IGCC in the Strategic Blueprint; however, in its comments at the technical conference, KIUC set forth a tentative solution to aid deployment of IGCC technology that would include a surcharge on all customers in conjunction with securitization.[220]

Externalities

The comments of the non-utility panel participants[221] and members of the public participating at the technical conference heavily referenced externalities. Externalities generally refer to external costs imposed without being accounted for in the cost of a product. Externalities can result from both production and consumption. There are potential externalities associated with the generation, transmission and distribution of electricity. With regard to transmission and distribution, these involve primarily aesthetics such as the loss of a view and the potential impact on property values. With generation, especially coal-fired generation, there are potential externalities associated

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[218] Id.

[219] Pre-filed Comments of KIUC, dated June 8, 2005 at 3 and 4.

[220] Id., and Transcript at 137 to 139.

[221] This includes: the KRC, ESG, Moore Environmental, Mr. Geoff Young, and Dr. Don Colliver.

with the extraction, transportation and combustion of coal. The most significant externality related to emissions from coal-fired generating units which are addressed in the Environmental Compliance section.

To address externalities, chiefly emissions, policy makers have historically used two distinct approaches. The traditional approach has been a command and control approach. This has included performance standards such as limits on emissions that were applicable across the board.[222] There have also been technology standards which required that generators use a specific technology.

The second approach and one that is relevant to electricity generation is that of market based incentives to achieve pollution reduction. This is often referred to as a cap and trade approach.[223] The 1990 Amendments to the Clean Air Act set a cap on the allowable emissions of sulfur dioxide ("SO_2"), a primary component in acid rain. This total amount was allocated among existing sources and these allocations or rights could be bought or sold in open markets as emission credits. This allows sources that can reduce emissions easily and cheaply to do so and sell their unused credits or save them for the future. Sources that found it more expensive to reduce emissions were able then to buy emission credits on the open market.

The externalities identified by non-utility panel participants ranged from pollution and pollution related costs to issues related to coal mining such as land reclamation, overweight trucks and slurry impoundments, to subsidization inherent in available tax

[222] Field, Barry. Environmental Economics—An Introduction. Second Edition. McGraw-Hill, 1997. Chapter 11: Command-and-Control Strategies: The Case of Standards, pp 210-229.

[223] "Clearing the Air, The Facts About Capping and Trading Emissions" US EPA, May 2002.

incentives and ratemaking practices. They strongly argued that there is a need to more fully account for externalities in the price of electricity. In essence, the bottom line to these participants is as the KRC noted: that the goals of the Governor's Executive Order and as set forth in the Commission's Order initiating this case can only be met with "policies that embrace full-cost accounting and not minimum regulatory compliance as the goal."[224]

According to the KRC, the "cost of energy has not historically incorporated environmental and public health costs associated with combustion of fossil fuels."[225] These costs have been recovered in another fashion in: "public and occupational injury and health impacts, environmental degradation, water and air pollution, and loss of economic opportunity."[226] The KRC argues that electricity and other energy products must be priced to account for the costs of producing and transporting fossil fuels. Furthermore, the KRC believes that this artificially low cost of electricity is the reason that conservation measures and investment in efficiency aren't more widespread.[227]

The KRC states that there are numerous externalities associated with the coal industry that must be addressed. These include construction of fills in watersheds, mining under homes, overweight trucks hauling on small rural roads, mining near and in streams, and dumping mine wastes in slurry impoundments. These externalities are in

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[224] Pre-filed Comments of KRC, dated June 8, 2005 at 3.

[225] Id. at 8.

[226] Id.

[227] Id. at 16.

addition to poor air quality and disruption of the use of public land for recreation.[228] It appears that the KRC expects the Commission to account for the negative impacts of the coal industry in pricing electricity, noting that how we do so will be key.[229]

The KRC also discusses its concerns with carbon emissions which it identifies as the "800 pound gorilla" that no one wants to acknowledge.[230] According to the KRC, the U.S. produces 22 percent of the world's CO_2 emissions and Kentucky's dependence on coal for electricity makes Kentucky more vulnerable than other states as policy shifts to address carbon emissions.[231] Therefore, the KRC believes that carbon sequestration and reduction must be central to the choice of electric generation technologies.[232]

In its written comments, ESG cites many of the same externalities as the KRC, explaining that these costs subsidize the energy industry and are not reflected in product costs, similar to KRC's comments.[233] These externalities are cited as barriers to investment in the future power infrastructure (DSM, conservation and energy efficiency technologies) according to ESG.

In his written comments, Mr. Young expands on his concept of whole-system design which combines energy efficiency technologies with ways to reduce energy requirements. According to Mr. Young, this can apply to a manufacturing process, a

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[228] Id. at 10.

[229] Id. at 14.

[230] Id. at 17.

[231] Id. at 18.

[232] Id. at 20.

[233] Pre-filed Testimony and Exhibits of Stephen A. Roosa, Ph.D., CBEP, CEM, CDSM at 1.

commercial building or a new home.[234] The major obstacle to the use of the whole-system design concept and greater use of conservation and energy efficiency measures according to Mr. Young is traditional ratemaking and the regulatory framework.[235] To resolve this, Mr. Young encourages the decoupling of energy sales from revenues and profit, particularly a form of decoupling called statistical recoupling.[236] The statistical recoupling recommended by Mr. Young requires a regression analysis to tie energy consumption to various factors such as degree days, number of customers and price.[237] He contends that the objective of decoupling is to eliminate the disincentive for investment in other technologies inherent in the traditional regulatory framework.[238] In addition to his comments on the regulatory framework, Mr. Young also briefly notes environmental externalities and the imposition of pollution taxes.[239]

In his written comments, the AG cites the General Agreement on Trade in Services ("GATS") currently being negotiated as a potential issue but had little information regarding its potential impact.[240]

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[234] Comments of Geoff Young, dated June 17, 2005 at 2.

[235] Id. at 3.

[236] Id. at 4 and 5.

[237] Id. at 5.

[238] Id. at 5 and 6.

[239] Transcript at 156 and 157.

[240] Pre-filed Comments of the Attorney General, dated June 6, 2005 at 4.

Environmental Compliance and Other Environmental Issues

In their comments, the jurisdictional electric utilities raised environmental compliance as an important issue to consider in developing an energy policy and also as a potential barrier to investment. Some of the non-utility participants also discussed the issue but from a somewhat different perspective. This section attempts to reflect the comments of all parties.

First Panel – Jurisdictional Electric Utilities Representatives

Big Rivers addressed environmental compliance because of the impact compliance requirements may have on the cost of power. Although its generating units are leased to WKE, under the terms of the lease agreement, Big Rivers is financially responsible for a portion of all capital improvements including those relating to environmental compliance and it will be required to true-up the costs of those improvements at the end of the lease based on a pre-established formula. Big Rivers stated that all eight of the coal-fired generating units it owns and leases will have scrubbers by 2006 and that all units have already been retrofitted for NOx compliance.[241] Big Rivers believes that reforms to the Clean Air Act should be meaningful and balanced. Big Rivers recommends a number of principles that should be followed when developing additional environmental legislation, be it state or federal.[242] Among the principles identified by Big Rivers are: programs should be flexible and include emissions trading; the magnitude of reductions should not impair fuel diversity; emission reduction programs should incorporate future rate certainty;

[241] Pre-filed Comments of Big Rivers, dated June 8, 2005 at 6.

[242] Id.

mercury reductions should be phased in and emissions reductions strategies should not include CO_2; programs should have sufficient lead time; and finally, phase-in periods; and emissions trading should be equitable.[243]

East Kentucky Power also noted that the cost of environmental compliance has had a significant impact on electricity costs and expects compliance costs to continue to rise. As an example, East Kentucky Power stated that it had recently spent an additional $69 million for compliance at the new Gilbert unit. As a not-for-profit entity, it states that it tries to minimize costs and that it had not had a base rate increase since 1983. East Kentucky Power explained that the environmental surcharge mechanism helps Kentucky's utilities meet compliance requirements, manage costs and continue to burn high-sulfur Kentucky coal.[244]

In its comments, Kentucky Power also discussed the increasing cost of environmental compliance. It advocates having a policy that keeps costs associated with burning Kentucky coal at reasonable levels and maintains reasonable electricity rates. Kentucky Power expects a continuing debate incorporating science and social and economic issues, and identifies the development of clean coal technology as a priority.[245] In discussing barriers, Kentucky Power explained that environmental policy to date had been reasonable and responsible but that if that policy becomes "confusing, conflicting and contradictory" costs will rise.[246]

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[243] Id. at 6 and 7.

[244] Pre-filed Comments of East Kentucky Power, dated June 8, 2005 at 3.

[245] Pre-filed Comments, dated June 8, 2005 at 2.

[246] Id. at 4.

Other than referencing environmental requirements in a broad fashion as an important issue, KU and LG&E did not discuss environmental compliance in their written or oral comments.

While it did not directly address environmental compliance in its comments, ULH&P noted that some restrictions regarding CO_2 emissions are likely and, as a result, some utilities may consider alternative technologies such as IGCC technology. ULH&P stated that the Commission should develop reasonable parameters for considering such alternatives in the IRP process. ULH&P also suggested that the legislature consider laws providing for cost recovery mechanisms and financial incentives.[247]

Second Panel - Electric Industry Representatives

PJM addressed the environmental issue from the perspective of land use challenges associated with construction of new transmission lines. PJM noted that considerable planning and forethought, along with consideration of new technology, will be needed to mitigate environmental siting impacts when faced with issues relating to traversing national forest land or other protected areas.[248]

Neither TVA nor MEPAK addressed environmental compliance issues in their comments. Kentucky Pioneer briefly noted several issues regarding environmental compliance. However, its comments were made in the context of identifying the benefits associated with the IGCC clean coal technology it plans to deploy. Kentucky Pioneer believes that as stricter emissions standards are enacted, IGCC technology will

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[247] Pre-filed Comments of ULH&P, dated June 8, 2005 at 5.

[248] Pre-filed Comments of PJM, dated June 9, 2005 at 7.

be more economical because it can achieve reductions at a lower cost.[249] In addition, Kentucky Pioneer cited the ability to sequester CO_2 and remove mercury more economically as two reasons to include IGCC technology in Kentucky's future energy plans.[250]

Third Panel – Consumer, Academia and Environmental Representatives

In the context of the cost recovery and rate certainty issue addressed in a later section, the AG argued that the recovery of environmental costs already places the burden of sustaining Kentucky's coal industry on electricity consumers. Further, the AG stated that, as the cost of environmental compliance increases, so does this burden.[251]

The KRC's comments included fairly considerable discussion regarding environmental issues, stating that we cannot balance energy development with environmental protection.[252] Other than the cost of environmental compliance, the KRC argues that the consumer's cost of electricity has not included the environmental and other costs associated with the combustion of fossil fuels. The majority of the KRC's comments are therefore provided to support its argument that these "externalities" should be reflected in the cost of electricity. The KRC warns that Kentucky's failure to anticipate the impact of carbon emission could have adverse consequences and

[249] Pre-filed Comments of Kentucky Pioneer, dated June 8, 2005 at 8.

[250] Id. at 8 and 9.

[251] Pre-filed Comments of the AG, dated June 6, 2005 at 5.

[252] Pre-filed Comments of KRC, dated June 8, 2005 at 4.

encourages the separation of regulatory agencies from those that promote the development of a particular energy sector.[253]

The EPPC addressed environmental and environmental compliance issues. EPPC noted that the demand for electricity is expected to grow and that, 281 gigawatts of new capacity will be needed by 2025. EPPC noted that Kentucky is well situated to meet the demand but must do so in an environmentally responsible manner as is emphasized in the Comprehensive Energy Strategy.[254] According to EPPC, since 1970, the amount of coal used to generate electricity has grown by 75 percent, while emissions from coal fired power plants are more than 40 percent lower.[255] In addition to the existing environmental regulations regarding coal fired electricity generation, EPPC noted that in March 2005, the Environmental Protection Agency ("EPA") released the Clean Air Interstate Rule ("CAIR") that permanently caps SO_2 and Nitrogen Oxide ("NOx").[256] CAIR is a multi-pollutant strategy to reduce SO_2 and NOx, which contribute to fine particle pollution and ground level ozone. Fine particles and ozone are associated with thousands of premature deaths and illnesses each year, according to the EPA.[257] According to the EPPC, "when fully implemented, (by 2015) EPA projects that CAIR will reduce SO_2 emissions in these states by over 70 percent and NOx

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[253] Id. at 17 to 19.

[254] Pre-filed Comments of the EPPC, dated June 9, 2005 at 1.

[255] Id. at 2.

[256] Id. at 3.

[257] http://www.epa.gov/cair

emissions by over 60 percent from 2003 levels (Kentucky's estimated emissions reductions under CAIR are 49 percent for SO_2 and 58 percent for NOx)."[258]

According to EPA data, this reduction equals 260,000 tons of SO_2 and 108,000 tons of NOx. As of 2004, nine Kentucky counties were designated nonattainment for EPA's health based standards for fine particle pollution. CAIR will help bring two of these counties into attainment for fine particles by 2010 and will reduce fine particle pollution in the remaining seven counties. According to the same data, as of 2004, eight Kentucky counties were designated nonattainment for EPA's health based standards for ground-level ozone pollution. By 2010, CAIR will bring all of these counties into attainment for ground-level ozone. According to the same modeling data, these changes will cost the affected states $3.6 billion (measured in 1999 dollars).[259] By the year 2015, it is estimated that the benefits of CAIR will reach $85-$100 billion in annual health benefits[260] and nearly $2 billion in annual visibility benefits in southeastern national parks, as well as significant reductions in acidic lakes and streams in the eastern U.S.[261] In Kentucky, EPA's modeling estimates CAIR's impact upon the average retail electricity price to be 3.4 mills/kWh by 2015.[262]

The Clean Air Mercury Rule ("Mercury Rule") was also released in March of 2005. This rule makes the United States the first country in the world to regulate

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[258] Pre-filed Comments of the EPPC, dated June 9, 2005 at 3.

[259] http://www.epa.gov/cair/state/ky.html as viewed on June 7, 2005.

[260] Pre-filed Comments of the EPPC, dated June 9, 2005 at 3.

[261] http://www.epa.gov/cair

[262] http://www.epa.gov/cair/state/ky.html as viewed on June 7, 2005.

mercury emissions from coal-fired power plants. According to EPA estimates, when fully implemented, these rules will result in a 70 percent reduction in utility mercury emissions. This is expected to be done in a cap and trade, market based manner.[263]

According to EPPC's comments, economic growth, greater efficiency and a move to meet and address higher electricity demands are expected to continue over the next two decades. Real economic growth is forecast to increase by an average of 3.1 percent per year through 2025. Reflecting greater efficiency, the use of energy will grow by a slower 1.4 percent per year on average or by a total of 35.5 percent. Consumption of all sources of energy will increase: petroleum by 39 percent, coal by 34 percent and renewable energy by 37 percent.[264] As EPPC observes, even though there have been improvements in environmental quality while increasing the use of coal, this increased demand for coal-fired electricity will demand more advanced clean coal technology. Investments in such technology will allow for Kentucky coal to be utilized as an important energy resource, while protecting the environment.[265]

As EPPC notes in its comments, according to the DOE, power plants utilizing IGCC generation "can significantly reduce air emissions, water consumption and solid waste production," and offer "the potential of a technical pathway for cost effective separation and capture of carbon dioxide emissions and for co-production of hydrogen."[266]

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[263] Pre-filed Comments of the EPPC, dated June 9, 2005 at 3.

[264] Id. at 4

[265] Id. at 5.

[266] Id. at 5.

In addition to emissions, EPPC discussed other regulatory programs such as the Clean Water Act and the federal Resource Conservation and Recovery Act that impact electricity generation in Kentucky. EPPC expects that these will become more stringent and more costly and will place upward pressure on the price of electricity nationally as well as in Kentucky.[267]

EPPC briefly mentioned several other environmental related issues that will impact the electric industry. These are: the multiple permits required for new and expanded energy facilities; surface mining issues and legal challenges to permits; authorization for water withdrawal for new and expanded energy facilities; and the declining level of the Kentucky Bond Pool which was created to assist small to medium size coal companies meet reclamation bond requirements.[268] Finally, EPPC noted that greater use of energy efficient products could be the most cost-effective and environmentally beneficial source of energy.[269]

ESG did not cite specific environmental concerns but argued for greater use of DSM programs and energy efficient products that would have the effect of somewhat limiting the need for environmental compliance. In its comments, KIUC indicated that it does not believe IGCC technology to be the answer to meeting increased environmental compliance and maintaining low rates. KIUC notes that IGCC technology is 17 to 19 percent more expensive because of higher capital costs and is a less reliable

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[267] Id. at 6.

[268] Id. at 7.

[269] Id. at 8.

technology than other types of coal-fired generation.[270] KIUC identified the option of securitization to reduce the financing cost of environmental control facilities.[271] Alcan and Century did not comment on environmental issues.

Public Comment

Participants in the public comment session did not discuss environmental compliance or other environmental issues in the same fashion or with the same concern as the utilities. Rather, they discussed environmental compliance and other environmental issues in the context of externalities, which if fully accounted for, would make both utilities and consumers more apt to seriously consider renewables, alternate technologies and greater use of energy efficient products and DSM initiatives. Since externalities are addressed in another section, only a very brief summary of the participants' environmental related comments will be addressed here.

Mr. Young noted that improved energy efficiency and greater use of DSM was Kentucky's most environmentally sound energy source.[272] His comments were directed toward ways to encourage greater use and consideration of both. Moore Environmental urged that consideration be given to using rapid growth woody perennials in electric generation to decrease environmental destruction. Moore Environmental recommended mandating the use of biomass crops for electric production to a level greater than 20 percent in less than 10 years.[273] Much like ESG on an earlier panel, Dr. Colliver urged

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[270] Pre-filed Comments of KIUC, dated June 8, 2005 at 3.

[271] Id. at 4.

[272] Comments of Geoff Young, dated June 20, 2005 at 6.

[273] Comments of Moore Environmental, dated June 22, 2005 at 1 and 3.

that efforts be directed toward greater use of energy efficient products to help protect environmental quality.[274] Peabody Energy referred to the new CAIR and Mercury Rule and stated that it would be in favor of Kentucky's pursuit of clean coal generation regardless of technology. However, Peabody Energy also stated that Kentucky can maintain its trend of improvements in air quality by incorporating new environmental control technology into existing generation.[275] Peabody Energy did identify the permitting and appeal process, relating to an air permit requested by its affiliate Thoroughbred Energy as a potential barrier to investment.[276]

Barriers to Investment - Generation

The Commission's May 26, 2005 letter to the proposed participants of the technical conference asked them to identify and discuss the top issues facing Kentucky's electric power industry in the next 20 years and any barriers "to future investment needs in electric power infrastructure in Kentucky."[277] This section addresses the barriers identified regarding generation, although in some cases the barrier discussed may apply to transmission as well.

First Panel – Jurisdictional Electric Utilities Representatives

In its pre-filed written comments and narrative comments at the technical conference, Big Rivers identified merchant plants as a barrier to future investment. According to Big Rivers, merchant plants would reduce the level of "legal emissions

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[274] Pre-filed Comments of Dr. Don Colliver, dated June13, 2005 at 3.

[275] Comments of Peabody Energy, dated June 20, 2005 at 1.

[276] Id. at 3.

[277] Commission's letter of May 26, 2005 to various individuals requesting participation in the June 14, 2005 Technical Conference.

capacity" available to jurisdictional utilities.[278] Although the merchant plants may be able to increase sales of coal by selling power out of state, they have no customer base or obligation to serve Kentucky customers. As available emissions capacity is reduced, the jurisdictional utility would have the responsibility to add controls to existing units or retire the units. If units are retired, the utility could build new generation or purchase power at market prices. In any case, Big Rivers argues that the result will be increased prices for electricity.[279] Although not specifically identified as barriers, Big Rivers discussed the issues relating to environmental compliance and RTO membership in the same context as barriers. Big Rivers expressed its concern with the direction of future environmental legislation and set forth principles to balance economic, energy and environmental goals. Regarding RTOs, Big Rivers noted that the benefits of membership did not offset the costs of membership and suggested that Kentucky reject RTO membership by its electric utilities unless increased reliability or lower cost to offset membership cost can be demonstrated.[280]

In its pre-filed written and narrative comments, East Kentucky Power cited the Kentucky Revenue Department's new policy regarding sales tax on electric facilities, the rising costs of fuel and environmental compliance, and the financial risks of deploying clean coal technology as barriers associated with the generation infrastructure.[281] East

[278] Pre-filed Comments of Big Rivers, dated June 8, 2005 at 9 and 10.

[279] Id.

[280] Id. at 7 and 8.

[281] Pre-filed Comments of East Kentucky Power, dated June 8, 2005 at 10.

Kentucky Power stated that it has been assessed almost $2 million in sales tax and penalties for the period from February 1, 2001 through November 30, 2004.[282]

Kentucky Power identified two barriers. First, it stated that public policy should be "sound, reasonable and responsible" as well as based on "solid information and sound science."[283] As an example, Kentucky Power cited the 1970 Clean Air Act and the emissions reductions that have been achieved as a result of the Act. Second, Kentucky Power cited the need to clearly define the roles of federal and state governments. Kentucky Power believes that FERC should continue to regulate wholesale energy markets and open transmission tariffs in addition to being given siting authority. According to Kentucky Power, FERC's authority should be applied as sort of a last resort to compensate for states that impede siting of projects (Kentucky Power classifies Kentucky as a state where siting works). Kentucky Power believes that the states should continue to have jurisdiction over generation and distribution.[284]

KU and LG&E did not specifically identify barriers separate from other issues but noted that the failure to clearly address the issues would result in barriers to future investment. KU and LG&E addressed the issue of jurisdictional certainty regarding federal and state authority, especially regarding RTOs. They cautioned that Kentucky must guard against jurisdictional expansion by FERC hindering its effective regulation of Kentucky utilities.[285] In addition, KU and LG&E noted the issue of regulatory certainty

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[282] East Kentucky Power's Response to a Technical Conference Data Request, dated June 14, 2005.

[283] Pre-filed Comments of Kentucky Power, dated June 8, 2005 at 4.

[284] Id.

[285] Pre-filed Comments of KU and LG&E, dated June 8, 2005 at 6 and 7.

as a potential barrier.[286] While explaining that the regulatory process worked well in Kentucky, KU and LG&E stated that regulatory lag and addressing the certainty of full cost recovery in the CPCN process could be considered.[287]

ULH&P noted several barriers, all relating to the regulatory process in some fashion. The first barrier noted by ULH&P was its concern that some participants in the regulatory process were advancing politically motivated arguments and not working toward constructive resolutions of issues. Another issue related to deregulation of the retail electric market where ULH&P urged the Commission and Legislature to continue a "wait and see" approach. ULH&P also cited the issue of resource planning and cautioned the Commission to continue to address resource planning issues on a case by case basis.[288] Finally, at the technical conference, ULH&P cited the change in the Kentucky Revenue Department's sales tax policy, which also impacts IOUs, as a potential barrier.[289]

Second Panel – Electric Industry Representatives

TVA did not specifically address barriers but stated its support for the initiative set forth by the Governor and the action of the Commission.

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[286] Transcript at 42.

[287] Id. at 43.

[288] Pre-filed Comments of ULH&P, dated June 8, 2005 at 2 and 3.

[289] Transcript at 28.

PJM did not identify barriers. However, PJM did state that its role in regional transmission planning would improve reliability, the economics of power flow and would open new markets for Kentucky coal-fired generation.[290]

MEPAK cited the absence of a "joint action authority" as a barrier to investment by its members. Joint action authority would enable the municipal electric systems to "join together to leverage their capacity and resources to contribute to the goal of making Kentucky an energy center for the nation and ensure long term low cost electricity."[291] MEPAK noted that there were 70 municipal joint action agencies in 36 states.[292]

The comments of the final panelist, Kentucky Pioneer, have previously been noted in the Renewable Resources and Alternative Generation Technology, Energy Efficiency, Demand-Side Management and Conservation and Externalities sections of this report and are listed here for information purposes. One of the major items set forth by Kentucky Pioneer related to IGCC technology including financing and deployment. In addition, Kentucky Pioneer cited the coal bias of Kentucky's Siting Law and its perceived misapplication of the Siting Law.

<u>Third Panel – Consumer, Academia and Environmental Representatives</u>

The comments of the majority of the participants on the last panel have also been previously noted in the Renewable Resources and Alternative Generation Technology, Energy Efficiency, Demand-Side Management and Conservation and

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[290] Pre-filed Comments of PJM, dated June 9, 2005 at 1.

[291] Pre-filed Comments of MEPAK, dated June 9, 2005 at 4.

[292] <u>Id.</u>

Externalities sections of this report and are listed here for information purposes. The AG did not identify any barriers in Kentucky but noted that GATS may impact our regulatory ability. The KRC addressed several issues as barriers but its predominant theme was the erroneous pricing signal sent due to the lack of fully accounting for all the impacts of having coal-fired generation as the major source of electricity. As previously noted, ESG recommended expansion of available DSM programs. ESG identified the perception of what is possible with DSM alternatives as the greatest barrier to future investment. KIUC, addressing comments made by other parties, discussed the risks associated with IGCCs and put forth a brief proposal to address these risks including joint ownership, securitization of debt and the imposition of a surcharge.

The focus of EPPC's comments related to challenges rather than barriers specifically. EPPC stated that the utilities needed a clear understanding of the environmental standards they will be required to meet. EPPC also identified investment in clean coal technology as a challenge that needed to be addressed. The processing and issuance of environmental permits were also noted as challenges. Finally, issues relating to the Kentucky Bond Pool need to be addressed, according to EPPC.[293]

Alcan and Century did not identify any barriers but noted their concern regarding their future power supply after their contracts with Kenergy expire.

[293] Pre-filed Comments of EPPC, date June 9, 2005.

Public Comment

There were four participants in the public comment portion of the technical conference. Many of their comments have been previously addressed but those relating to barriers to investment are noted below:

In his comments, Geoff Young emphasized some of the remarks made by earlier panelists. Like the KRC, he argued that the external costs associated with coal-fired energy should be internalized. One method to do so would be to impose a pollution tax; another would to require the estimation of the cost of externalities in the IRP process. Another point emphasized by Mr. Young was the idea of decoupling price from revenue in the ratemaking process.[294]

Moore Environmental did not identify any barriers but requested that the Commission mandate the use of renewables as part of the energy supply mix.

Dr. Don Colliver did not identify any specific barriers but discussed the fact that there was not a great recognition of the energy efficiency measures available and of the impact they could have.[295]

The final participant was Peabody Energy which has an affiliate that has been granted a conditional construction certificate for a merchant plant by the Kentucky Siting Board. In its comments, Peabody characterized Kentucky's transmission system as weak and as a possible barrier to investment in generation. Peabody also cited certain

[294] Comments of Geoff Young, dated June 20, 2005.

[295] Pre-filed Comments of Dr. Donald Colliver, dated June 13, 2005.

areas within the regulatory process relating to siting certificates and obtaining air permits.[296]

In his written comments, the AG cites the GATS currently being negotiated as a potential issue.[297] A working group of public officials has just started reviewing the impact of GATS on energy and the AG has offered to provide more information as it becomes available.

Rate Certainty, Cost Recovery and Other Regulatory Issues

In both written and oral comments, rate certainty, cost recovery and other regulatory issues were addressed by several parties.

Comments of the Jurisdictional Utilities

Although it provided no detailed discussion, Big Rivers cited regulatory certainty as something that should be incorporated in programs to reduce emissions.[298]

East Kentucky Power did not specifically address the issues of cost recovery or regulatory certainty. It did, however, express concern with rising fuel, environmental and other operating costs.[299]

Kentucky Power suggested that an issue for future consideration was a review of traditional ratemaking. Kentucky Power noted that it was especially important to be certain of recovery of investments made to meet state and federal requirements.[300] It

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[296] Comments of Peabody Energy, dated June 20, 2005.

[297] Pre-filed Comments of the Attorney General, dated June 6, 2005 at 4.

[298] Pre-filed Comments of Big Rivers, dated June 8, 2005 at 7.

[299] Pre-filed Comments of East Kentucky Power, dated June 8, 2005 at10.

[300] Transcript at 32.

suggested that a pre-approval process for major construction projects be considered. Finally, Kentucky Power recommended that allowing recovery of construction costs during the construction period be considered in an effort to keep costs down.[301]

KU and LG&E explained that, from their perspective, the regulatory framework in Kentucky had worked well by providing a balance of "wise regulation and good utility practice" and that the Commission had established a balance of interests between customers and utilities."[302] However, KU and LG&E stated that "regulatory lag" should not be a cost of doing business in Kentucky.[303] They claimed that, if a base rate case was the only vehicle available to recover increasing infrastructure and related costs, they would be put in an under earnings position that could affect their credit rating. Allowing utilities to fully recover costs for investments pre-approved under the current CPCN process could reduce uncertainty. Utilities could proceed at their own risk and the issue of capital recovery would still be addressed in a future rate proceeding.[304]

ULH&P stated that the adequacy of cost recovery was as important to it as it was to the other utilities and urged that any legislative or regulatory changes provide more certainty in terms of recovery of the cost of transmission, distribution and generation assets.[305] ULH&P discussed the importance of timely cost recovery of distribution system investments. ULH&P cited the AG's challenge to its gas distribution main

[301] Pre-filed Comments of Kentucky Power, dated June 8, 2005 at 4 and Transcript at 32.

[302] Pre-filed Comments of KU and LG&E, dated June 8, 2005 at 2.

[303] Id. at 4.

[304] Id. at 4 and 5 and Transcript at 41 to 43.

[305] Transcript at 27 and 28.

replacement tracker as a hindrance that was addressed by the 2005 General Assembly and recommended that such trackers be considered for application to electric utilities.[306]

Comments of Others

"If it ain't broke, don't fix it."[307] These words sum up the AG's beliefs regarding suggestions by the utilities that some consideration be given to changing the regulatory compact. The AG does not believe there is need for any changes to the regulatory scheme and does not believe that there are regulatory barriers to future investment.[308] In short, the AG recommended that the regulatory framework be left alone."[309]

KIUC stated that Kentucky's low cost advantage could not be maintained if unnecessary rate recovery devices were implemented that accelerated cost recovery. According to KIUC, current rate recovery mechanisms appear to be adequate and there is no evidence that new riders or surcharges are needed.[310] In its comments at the technical conference, KIUC set forth a proposal to aid deployment of IGCC technology which would include a surcharge on all customers in conjunction with securitization.[311] KIUC also proposed considering securitization as a means to reduce financing costs of environmental control assets.[312]

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306 Pre-filed Comments of ULH&P, dated June 8, 2005 at 7.

307 Transcript at 99.

308 Pre-filed Comments of the AG, dated June 6, 2005 at 2 and 3.

309 Transcript at 102.

310 Pre-filed Comments of KIUC, dated June 8, 2005 at 2.

311 Pre-filed Comments of KIUC, dated June 8, 2005 at 3 and 4, and Transcript at 137 to 139.

312 Pre-filed Comments of KIUC, dated June 8, 2005 at 4.

The KRC did not address regulatory certainty in the same manner as others. However, implementing its proposal to include the full cost associated with coal-fired generation in electric rates could have a significant impact on the utilities. Moore Environmental's comments did not directly address rate certainty either. But like the KRC's proposal, Moore Environmental's proposal to mandate that a utility's generation mix include a certain amount of renewable generation could also have a significant impact. Mr. Young's proposal regarding decoupling does not address rate certainty but his proposed solution, statistical recoupling, would set a somewhat permanent revenue requirement for each utility.

Other Regulatory Issues

MISO

MISO did not request formal intervention nor appear at the technical conference. It did, however, submit comments pursuant to the Commission's May 11, 2005 Order. As was noted in the Transmission section, since the MISO transmission system spans 15 states including Kentucky, it is required to assess infrastructure need on a regional basis.[313]

MISO stated that it was unable to identify any Kentucky specific issues but that on a regional basis "continued loop flows from regional energy transactions that heavily impact the Kentucky transmission system are likely to increase" and may have a significant impact on Kentucky's transmission facilities.[314] MISO also indicated that it

[313] Pre-filed Comments of MISO, dated June 8, 2005 at 1.

[314] Id. at 5 and 6.

was not in a position to address barriers to future investment in Kentucky but that in any region the principal concern is the ability to recover the costs of investment.[315]

Smelter Load

In a May 18, 2005 joint petition, Alcan and Century asked the Commission to require Kenergy to respond to certain items in the Staff's First Data Request relating to generation planning, generation resources and load requirements.[316] According to Alcan and Century, since the distribution cooperatives were not required to respond to these questions, information regarding the smelter load and the future adequacy of electric service was not complete because of the complex arrangement among the smelters, Big Rivers and Kenergy.[317] On May 27, 2005, the Commission ordered Big Rivers to explain why its resources would not be used to serve the smelters after 2010/2011 and Kenergy to respond to the requested items and provide any other information to explain how it intended to serve the smelters after contract expiration.[318]

Under the reorganization plan, Kenergy has power supply agreements with LEM to serve the Tier 1 and Tier 2 requirements of Alcan and Century. Tier 3 service is met by wholesale power market acquisitions, some of which come from Big Rivers.[319]

In its response, Big Rivers stated that as a result of its reorganization, it has no responsibility to supply wholesale power to the smelters nor are the smelters required to

[315] Id. at 6.

[316] Joint Motion of Alcan and Century, filed May 18, 2005 at 2.

[317] Id.

[318] Order, dated May 27, 2005 at 1 and 2.

[319] Big Rivers' Response to the Commission's data Request, dated May 27, 2005 at 4.

purchase wholesale power from Big Rivers.[320] Finally, to clarify the issue, Big Rivers cited the reorganization plan testimony of Alcan where Alcan stated its understanding of the provisions of the plan relating to the smelters; "the smelters are giving up the likelihood that Big Rivers [sic] rates will be below market in 2012 in return for the certainty that their rates will not be above market."[321] However, Big Rivers did state that it plans to continue to supply capacity and energy to the smelters beyond 2010/2011 on the same basis as it now.[322] Big Rivers further stated that it had not been asked to make a formal proposal to sell power to Kenergy for the smelters beyond 2010/2011 but that it had met with the smelters to explore how it could help them address their power requirement needs, including discussing the possibility of adding a second generating unit at its Wilson Station.[323]

Kenergy, in its response, echoed the position of Big Rivers, citing the service agreements entered with the smelters as part of the reorganization plan. The section cited stated that upon expiration of the agreements, the smelters have no obligation to purchase energy, capacity or transmission service from Kenergy and Kenergy will have no obligation to provide such to the smelters.[324] Kenergy did acknowledge that it had service responsibilities beyond the contracts and stated that if new service agreements

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[320] Id.

[321] Id. at 5.

[322] Id. at 1 to 4.

[323] Id. at 2 and 5.

[324] Kenergy's Response to the Staff Data Request, dated May 27, 2005 at 1.

can not be reached it would attempt to obtain wholesale power for the smelters at prices acceptable to the smelters.[325]

In their pre-filed comments, Alcan and Century acknowledge that, pursuant to the new service agreements arising from the reorganization plan, the responsibility to serve them was transferred from Kenergy to LEM for the term of the contract.[326] The smelters also acknowledge that, upon expiration of the contracts, Kenergy will have rights and obligations to them pursuant to statute.[327] However, the smelters state that if Kenergy plans to meet their supply needs with wholesale market power, they will not be able to continue operations if required to pay anticipated market prices.[328]

In their comments, the smelters note that the wholesale energy market has failed to evolve as anticipated. They also cite the results of actions regarding three other smelters in West Virginia, Missouri and Ohio. The smelters in West Virginia and Missouri that are subject to rate regulation continue in operation while the smelter in Ohio which became subject to market-priced power has discontinued operations.[329]

Recognizing that the resources available to Big Rivers at contract expiration will not be sufficient to serve them, Alcan and Century offer several alternatives for consideration. The first would be for Kenergy to allow the smelters to be transferred to another Kentucky supplier. The smelters note that the Commission can authorize such

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[325] Id.

[326] Pre-filed Comments of Alcan and Century, dated June 8, 2005 at 3 and 4.

[327] Id. at 5.

[328] Id. at 6.

[329] Id. at 6 and 7.

action upon a showing that Kenergy is unable to supply the smelters. A second option offered by the smelters would be for Kenergy to purchase power from other Kentucky utilities at rates they would charge similar customers and resell the power to the smelters. According to the smelters, another option would be for Kenergy to build new generation capacity.[330]

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[330] Id. at 7 and 8

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