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
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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 purchas-

ing “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

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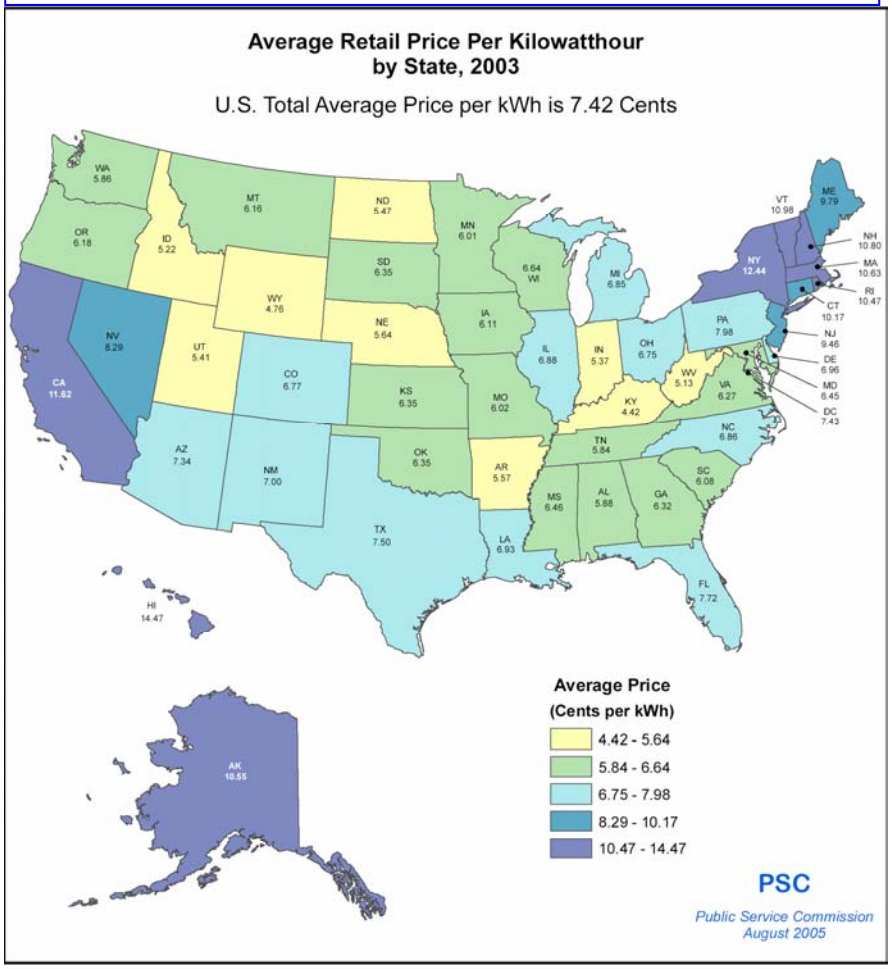
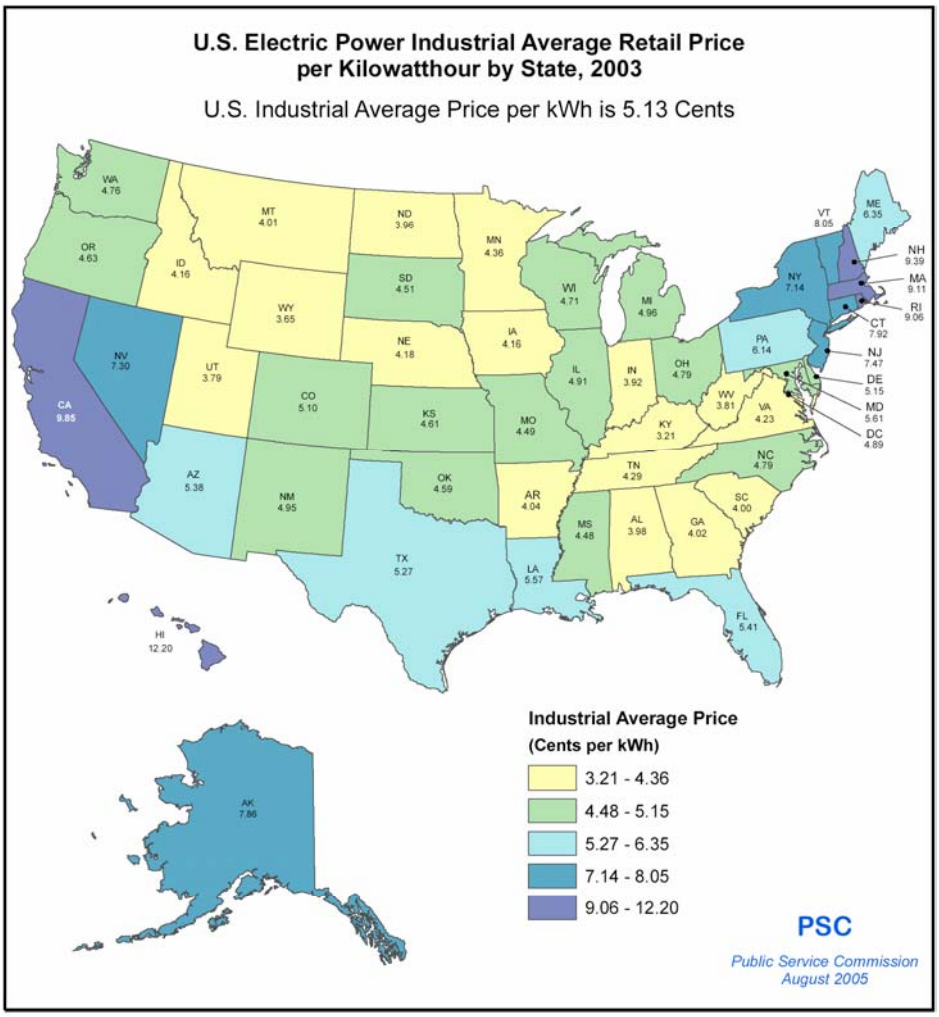


Source: Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Data".

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

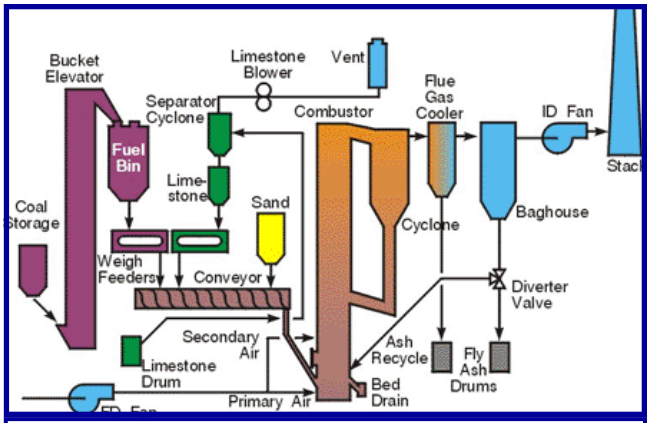
East Kentucky Power is a not-for-profit G&T utility which provides wholesale electric service to 16 member/owner distribution cooperatives in 89 counties throughout eastern and central Kentucky. Through these distribution cooperatives, it serves approximately 475,000 retail customers. In addition to 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 re-evaluated 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 re-

duced 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
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
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

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.

Merchant Plant Economics

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**

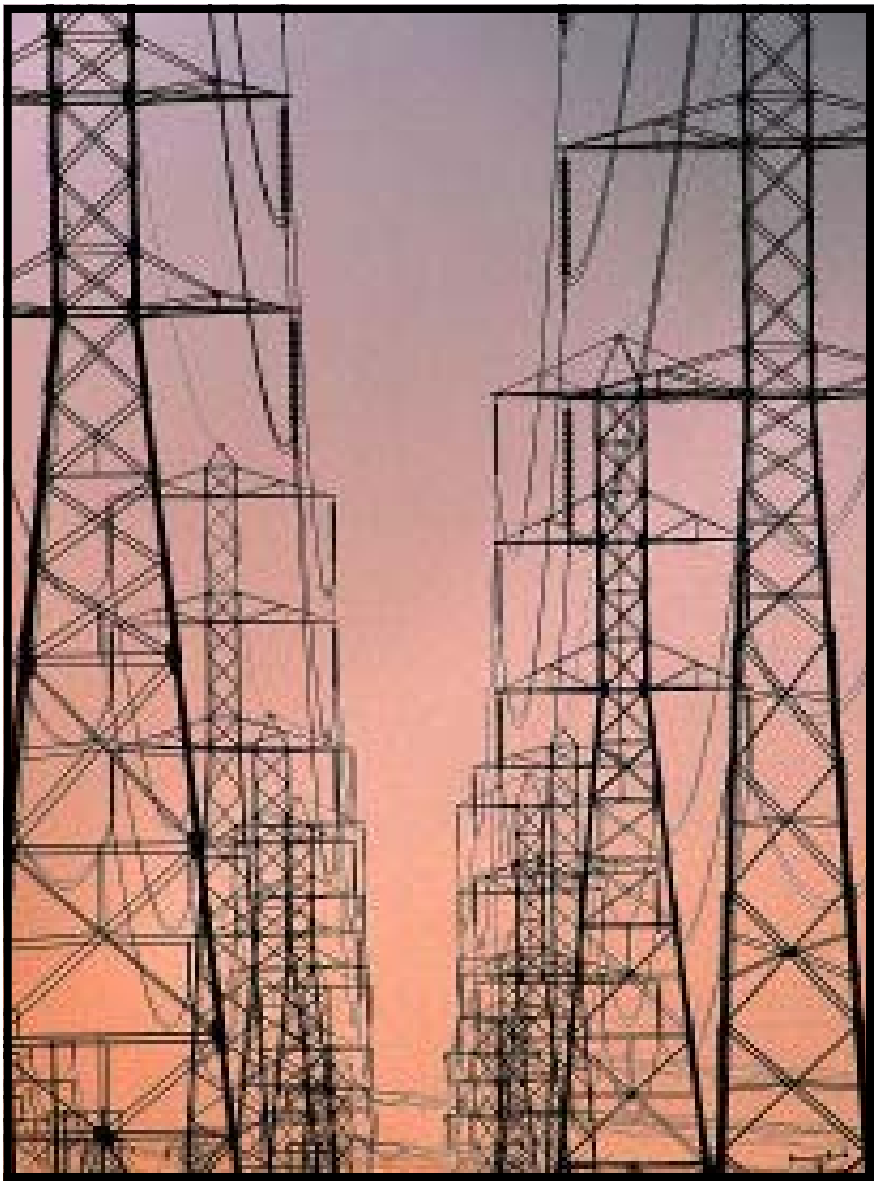
Numbers derived from the Public Service Commission's GIS database for Electric Transmission collected in 2001-2004.

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).)

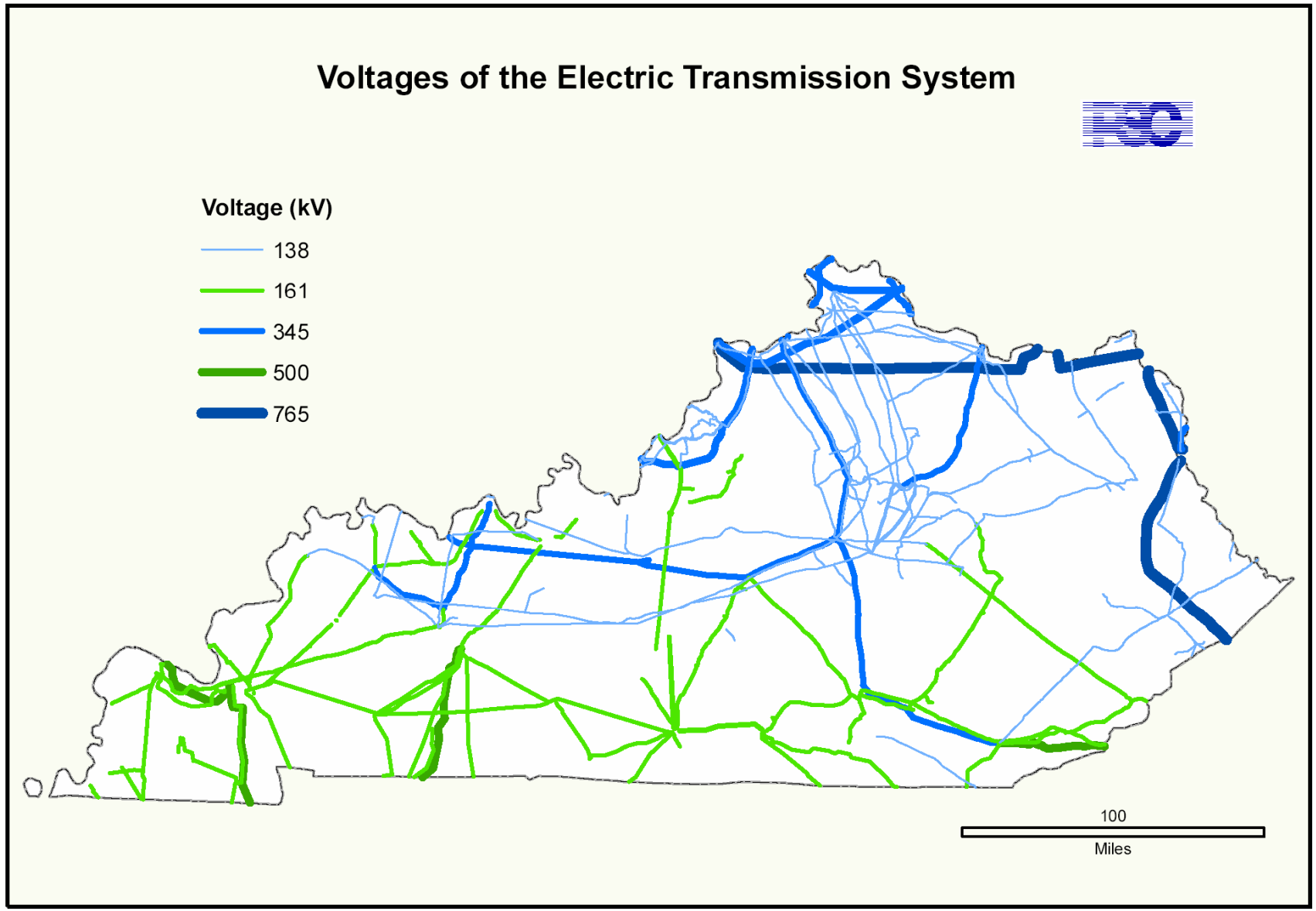
Each jurisdictional high voltage transmission owner has certified to the Commission that it has addressed each of the scenarios identified as potential problems in the CAI study to minimize the risk of widespread outage from them. TVA is not jurisdictional to the Commission but its transmission planners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

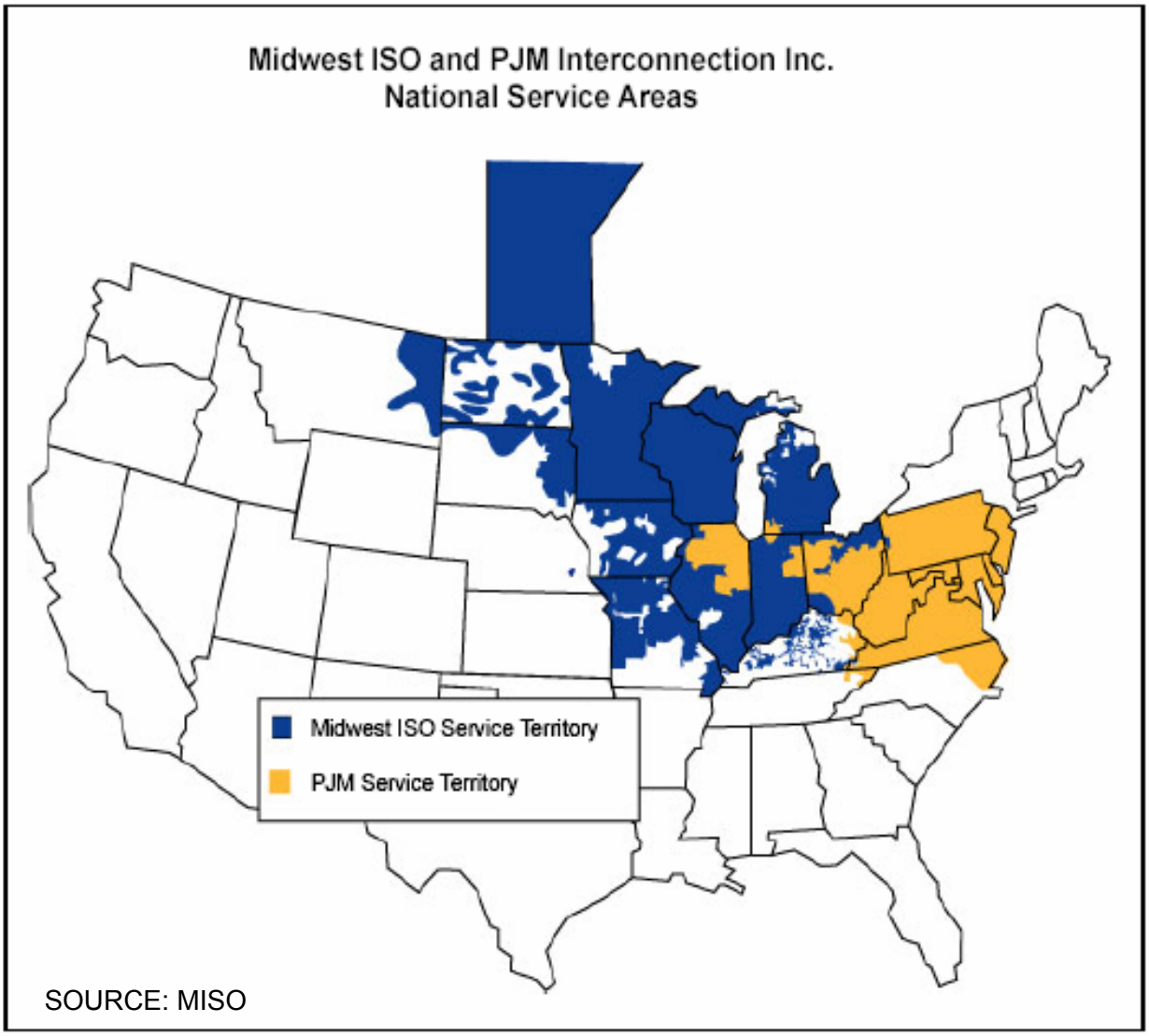
Big Rivers provided budget information. The information provided by the other utilities is actual cost.

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.



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

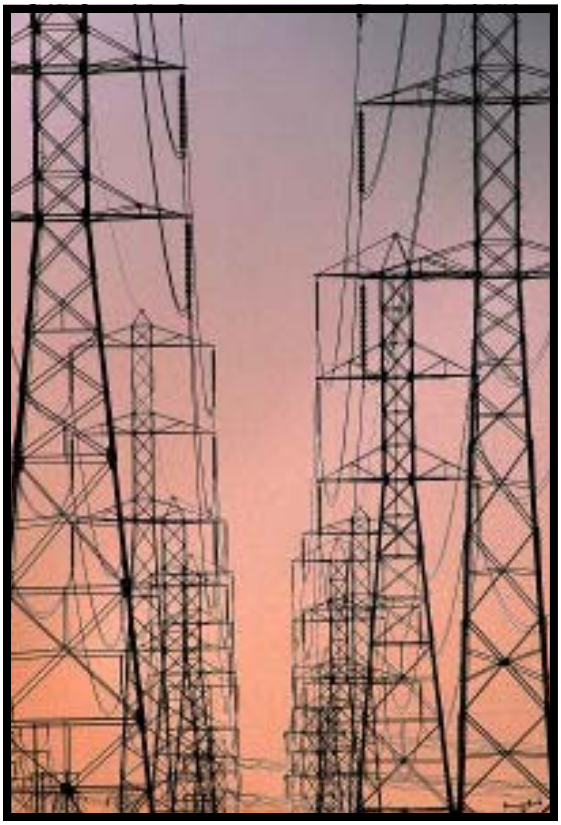
should be encouraged to investigate new and developing technologies that can increase the capacity of existing transmission facilities.

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.

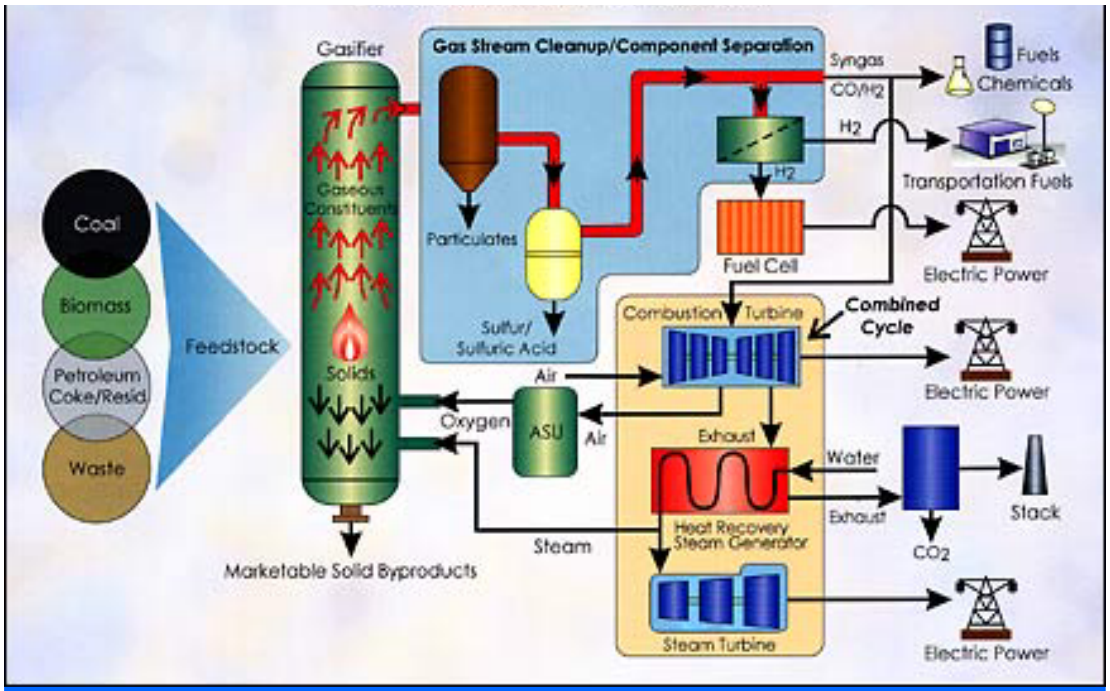
Promoting energy efficient practices, examining building codes, and increasing public awareness and education on energy efficiency issues are efforts that the Commission believes should be pursued by Kentucky's public policy makers. As we also note in discussing environmental compliance issues, greater 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, transmis-

sion 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.

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