Restructuring Kentucky's Electric Utility Industry:

An Assessment of and Recommendation for Future Action in Kentucky

Final Report Special Task Force on Electricity Restructuring

Research Report No. 299

LEGISLATIVE RESEARCH COMMISSION
Frankfort, Kentucky 40601

September 2000

Restructuring Kentucky's Electric Utility Industry

Special Task Force on Electricity Restructuring

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FOREWORD

The Special Task Force on Electricity Restructuring was established in 1998 by House Joint Resolution 95 to examine the impact of restructuring Kentucky's electric utility industry. The purpose of this report is two-fold. First, the report provides a basic understanding of electricity restructuring both in broad terms and as pertains to Kentucky. Second, the report documents the activity of the task force including research conducted on its behalf.

This report is the product of a collaborative effort between staff at the Legislative Research Commission (LRC), the Public Service Commission (PSC), and Resource Data International (RDI). Special thanks to the staff economists and financial analysts at the LRC and the PSC: Mike Clark, Perry Nutt, Monica Greer, Neal Fitch, and Issac Scott. Additional thanks to the project oversight and coordination efforts provided by PSC staff Aaron Greenwell and Ralph Dennis. Suggestions and corrections were provided by RDI's Chris Seiple and LRC's Linda Kubala, Todd Littlefield, and Sheri Mahan. This report was written by LRC staff Tanya Monsanto with assistance from Neal Fitch and Chris Seiple.

Robert Sherman, Director
Legislative Research Commission

The Capitol
Frankfort, Kentucky
April 15, 2000

TRANSMITTAL MEMORANDUM

TO: The Honorable Paul E. Patton, Governor
The Legislative Research Commission

FROM: Senator Larry Saunders, Co-Chair
Representative Larry Clark, Co-Chair
Mr. Jack Conway, Co-Chair

DATE: August 10, 2000

RE: Final Report of the Special Task Force on Electricity Restructuring

Attached is the final report of the Special Task Force on Electricity Restructuring. The Findings and Recommendations were approved by the Task Force on December 13, 1999, and are incorporated into this report.

The report explains in general terms what electricity restructuring is and how restructuring would affect utilities and customers in Kentucky. The report concluded that there is no compelling reason for the Commonwealth to restructure the electric utility industry at this time and recommended that no action be taken in the 2000 session. The report also concluded that the General Assembly should continue to study the issue.

Questions concerning this study should be addressed to Dan Risch, Committee Staff Administrator for Agriculture, Natural Resources and Energy.

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SUMMARY

Creation of Special Task Force on Electricity Restructuring

House Joint Resolution (HJR) 95, passed during the 1998 session of the General Assembly, established the Special Task Force on Electricity Restructuring. This task force was directed to study the issue of electricity restructuring and to determine its impact on Kentucky. Out of the study process, the task force developed both findings of fact and recommendations for future action regarding restructuring the electric utility industry in the Commonwealth. The findings and recommendations were to be submitted to the Governor and to the Legislative Research Commission (LRC) by November 15, 1999. A request to extend the submission date to December 15, 1999, was approved by the LRC on November 2, 1999.

Activities of the Special Task Force

The Task Force adopted a deliberative approach to studying the issue. The task force met 14 times between September 1998 and December 1999. During that time, the task force heard from various stakeholders including utilities, consumer advocates, public agencies, and large industrial users of electricity. A public hearing was held to solicit comments from the general public. Complex information about specific issues related to restructuring was obtained from various experts in the area of electricity restructuring. Finally, the task force heard from legislators in states that had either adopted, or were in the process of adopting, restructuring legislation.

Consultant Reports Delivered to the Special Task Force

Specific technical information was required to fully understand restructuring's impact on Kentucky. Therefore, on December 3, 1998, the task force issued a Request for Proposals (RFP) to obtain specialized consulting services (See Appendix C). Central to the consultants' work was the preparation of four reports that answer seven questions about restructuring's impact on Kentucky listed in the RFP.

In January 1999, the task force hired Resource Data International (RDI) to provide consulting services. In accordance with the RFP, RDI worked with a staff team from the Public Service Commission (PSC) and the Legislative Research Commission (LRC) to produce four separate interim reports on restructuring. Findings from the interim reports were presented to the task force and are used as the basis for preparing the findings contained in this final report of the task force.

A summary on each of the four interim reports is contained in Chapter 3 of this report. The interim reports are as follows:

1. Interim Report No. 1: Marginal Cost of Electricity and Urban/Rural Impacts in a Restructured Electric Industry;
2. Interim Report No. 2: Stranded Costs and Electricity Exports in a Restructured Electric Industry;
3. Interim Report No. 3: Impacts of Electric Deregulation on the Kentucky Coal Industry and an Overview of Affiliate Transaction Issues; and
4. Interim Report No. 4: Potential for Market Power Abuse in a Restructured Electricity Market.

Major Findings and Recommendations of the Special Task Force

The task force adopted nine major findings and two recommendations.The findings reflect significant information about changes in the electric utility industry and how those changes will affect Kentucky today and in the future. The findings are grounded in the research provided by RDI and in the testimony received from recognized experts in the field of electricity restructuring. Both the findings and the recommendations are presented below.

Task Force Findings

1. There is no compelling reason at this time for Kentucky to move quickly to restructure. Despite the prospects of Congressional legislation to mandate restructuring, actions taken by 23 states to restructure, and the fact that some of those states are geographically contiguous to Kentucky, there are obvious advantages for Kentucky's adopting a wait-and-see approach to electricity restructuring. Congressional action to pass a nationwide restructuring bill appears unlikely at this time. Representatives from other states that have restructured as well as experts in the field of electricity restructuring indicate that Kentucky is in a unique position because of its existing low electricity rates, which currently are the lowest east of the Rocky Mountains. A wait-and-see approach allows Kentucky to monitor the progress of restructuring in other states and to develop options that protect Kentucky's existing low rates for electricity.

2. Restructuring is expected to have multiple effects on Kentucky's electricity prices.

   A. Restructuring would be expected to cause greater variability in electricity rates over time. If Kentucky's electricity rates are deregulated, price fluctuations would be expected to be larger in magnitude than fluctuations

under cost-of-service regulation. Analysis conducted by RDI indicates that prices will increase as the amount of excess capacity in the generation market decreases. Electricity rates also were found to fluctuate in response to changes in fuel prices, particularly the cost of natural gas. Finally, RDI analysis shows that deregulated electricity prices can dramatically increase during "severe" electric conditions characterized by unplanned transmission and generation outages. During these "severe" conditions, the potential exists for utilities to raise prices above the competitive market price.

B. Price gains from restructuring are predicated heavily upon excess generating capacity in the electricity market. In the short run, RDI analysis shows that as excess generation capacity is reduced, the deregulated price of electricity rises, and the regulated price of electricity remains relatively unchanged. The only scenario showing sustained price reductions over the long run, even as capacity declines, occurs when improvements are made in the transmission and generation infrastructure and a reduction occurs in the utility's production costs.

C. Increases in fuel prices are expected to make electricity more costly than current, regulated prices. Conversely, a reduction in fuel prices alone is expected to make electricity prices fall in the short run**.** RDI's analysis shows that when gas prices are increased by twenty percent, and the market demands greater capacity reserves, the deregulated price for electricity is consistently higher than the regulated rate. When gas prices are reduced by ten percent, the electricity price is lowered only during the first three years. After the third year, the deregulated price increases to a point where both the regulated and deregulated prices converge.

D. Deregulated generation rates would be expected to vary across the state in accordance with the existing utility's current cost of producing power. Currently, the cost of generating and delivering electricity varies on a utility-by-utility basis. RDI contends that some higher-cost utilities will have to reduce their prices in order to be competitive in a deregulated market. Conversely, customers of utilities whose current cost of production is below the expected deregulated price of electricity may face price increases.

3. Restructuring is not expected to have a negative impact on electricity rates in rural areas. There are three components to the electricity bill: generation, transmission, and distribution. According to RDI analysis, customers in rural areas have traditionally had higher average electricity rates compared to customers in urban areas. The disparity in rural/urban electricity rates is primarily due to relative differences in distribution costs. However, RDI analysis shows that the cost of generation would not vary in accordance with the population density of the market. The cost of acquiring a customer in a

rural area is the same as that of acquiring a customer in an urban area. Therefore, rural customers are expected to have higher distribution costs than urban customers in a restructured market, but rural customers are expected to receive the same generation price as urban customers in a restructured market.

4. Kentucky does not face sizable positive stranded costs in comparison with higher-cost states; however, Kentucky does have considerable variations in both positive and negative stranded costs on a utility-by-utility basis**.**

   A. Positive stranded costs are comprised of purchase power contracts and are concentrated in three utilities: Cinergy's Union Light Heat & Power, Big Rivers, and distribution utilities served by TVA. Their positive stranded costs collectively could range from $295 million to over $1 billion.[1] The remaining utilities are in a "negative stranded cost" position, which means that the market value of their generating assets and purchase power contracts is higher than the book value for these assets in a regulated market. Potential negative stranded costs in Kentucky range from nearly $700 million to $3.7 billion.[2]

   B. The negative stranded cost position borne by most of the utilities in Kentucky is the result of three principal factors: lower-cost coal resources for generating stations, the lack of nuclear power in Kentucky, and the use of "construction work in progress" to finance the construction of generating stations. Construction work in progress allows the utility to charge current customers for the cost of building a power plant before the plant goes on-line.

   C. The imposition of a stranded cost recovery mechanism would probably not uniformly impact all customers in Kentucky. The reason for this is two-fold: First, some Kentucky customers currently served by utilities that purchase power from TVA could not be subjected to a stranded cost recovery charge imposed by either the legislature or the PSC. TVA customers in Kentucky, who are served by utilities that have positive stranded costs, are subject to the exclusive jurisdiction of the TVA. Second, positive and negative stranded costs vary based on each utility's cost of supplying power. Therefore, the potential exists for electricity prices to rise at lower-cost utilities and fall at higher-cost utilities. If the stranded cost recovery mechanism is applied only to those customers who exit the system, existing customers of higher-cost utilities may bear a disproportionate burden for stranded costs.

5. Restructuring is not expected to negatively impact the coal industry in Kentucky. Approximately 77 percent of Kentucky's coal is sold out of state and would not be affected by a decision to restructure Kentucky's electric utility industry. The remaining 20 percent of Kentucky's coal market could be

affected by a decision to restructure Kentucky's electric utility industry. But given the relatively low cost of producing power at Kentucky's coal fired generators, restructuring is not expected to reduce in-state sales of Kentucky coal. Power plants in Kentucky that use Kentucky coal are well positioned in a restructured market. Not only are Kentucky coal plants not expected to face retirement, but these plants may increase their coal utilization rates. Current declines in the production of both Western and Eastern Kentucky coal are primarily related to other factors affecting the coal industry such as stricter air emissions controls promulgated by the U.S. Environmental Protection Agency (EPA), decreasing transportation costs for coal, and price differentials between Kentucky and coal from the western U.S., such as that of Powder River Basin (Wyoming). Restructuring is not expected to affect any of these other factors.

6. Restructuring is not expected to reduce the importance of natural gas in new generating capacity in Kentucky. Within the past ten years, all new capacity in Kentucky has been gas-fired. The last coal-fired generation unit, LG&E's Trimble County plant, came on-line during the early 1990s. As the cost advantage for gas-fired generation continues to increase, and demand for electricity continues to grow during summer peaking months, the expectation is that new capacity will be gas-fired combustion turbines. These gas units would be used exclusively for peaking purposes.

7. Restructuring is not expected to lead to dramatic outflows of Kentucky electricity to higher-cost states. Approximately 7.5 percent of Kentucky's total generation has been exported since 1995. However, RDI analysis shows that exports of electricity are expected to increase to 9 percent in the short-term if the Midwest Independent System Operator (ISO) becomes functional. This is because formation of the ISO is expected to lead to a single "postage stamp" type rate that will eliminate "pancaking" (the multiple rates charged by each transmission owner when transporting power for another supplier). RDI estimates that as demand for power grows within Kentucky, exports will decline to 5-7 percent of total generation over the long-term.

8. Absent new market rules for conduct and cost allocation between regulated utilities and unregulated affiliates, the potential exists for an uneven playing field to develop between unregulated affiliates and existing firms in competitive, unregulated product and service markets. Regulated electric utilities are reorganizing and expanding their unregulated holdings at a very rapid rate. Unregulated holdings are being concentrated in energy-related businesses such as electricity commodity sales, metering and billing, energy conservation, electrical contracting, heating, ventilation and cooling (HVAC), related fuels, and appliance repair. On a nationwide basis, unregulated businesses of regulated utilities are putting competitive pressure on existing firms. According to RDI, there is an inherent conflict in a utility's organization between the need for stricter, sometimes burdensome compliance mechanisms

and the drive to succeed in newly competitive electricity markets. To prevent cross-subsidy of competitive businesses by the regulated utility and to protect customers from potential abuses of market power, some states have put restrictions on an affiliate's use of name and logo, prescribed cost allocation guidelines, established a code of conduct, and required periodic compliance audits. The Kentucky Public Service Commission is addressing these and other related issues in Administrative Case No. 369.

9. Under severe market conditions, larger utilities in Kentucky such as AEP and TVA may have significant market share and control over transmission assets to withhold generation supplies and significantly distort electricity prices. Smaller utilities do not have the market share or control over transmission assets to withhold generation supplies and significantly distort electricity prices.

   A. When a utility exerts market power, it is able to significantly increase profitability by 5 percent or more over a wide range of demand conditions. Because the East Central Area Reliability (ECAR) is comprised of a highly interconnected transmission system that poses few barriers to entry by new market entrants in generation, very few companies in Kentucky have the ability to sustain profits above those seen in a perfectly competitive market.

   B. With the exception of TVA and AEP under certain limited circumstances, no utility in Kentucky currently has the potential to exert market power. However, AEP may have sufficient market presence to exercise market power during peak demand conditions. According to RDI, merger and acquisition activities are likely to continue in the future, and consolidation of existing utilities in the region does pose the threat of creating future market power situations.

   C. Utilities in Kentucky may be able to exert market power in areas known as "load pockets." Load pockets constitute smaller geographic areas that are not as well interconnected to the transmission grid and sometimes arise out of unplanned transmission outages or constraints. Because competitive suppliers are unable to reach customers in the load pocket, and because there is no regulation over the generation supplier in a deregulated market, the potential exists for utilities to charge above the competitive price of electricity in that market.

Task Force Recommendations

1. The task force recommends that no action be taken during the 2000 session of the General Assembly to restructure Kentucky's electric utility industry.

2. The task force recommends that the General Assembly continue to study the issue of retail competition. The task force also recommends that the General Assembly monitor actions taken in other states that have opened their retail markets to competition and to address other issues, such as reliability of service, transmission, and consumer education. Action should be taken during the 2000 Session of the General Assembly to reauthorize the Special Task Force on Electricity Restructuring.

GLOSSARY OF TERMS

Average Cost	The revenue requirement of a utility divided by the utility's kilowatt-hour sales. Average costs typically includes the costs of existing power plants, transmission, and distribution lines, and other facilities used by a utility to serve its customers. It also includes operations and maintenance, tax and fuel expenses.
Avoided Cost	The cost of alternative energy that the utility would have to generate or purchase from another source.
Deregulation	The elimination of regulation from a previously regulated industry or sector of an industry.
Direct Access	The ability of a retail customer to purchase commodity electricity directly from the wholesale market rather than through a local distribution utility.
Energy Efficiency	Using less energy/electricity to perform the same function. Programs designed to use electricity more efficiently.
EPAct	The federal Energy Policy Act of 1992.
Exempt Wholesale Generator (EWG)	Created by the Energy Policy Act of 1992. These generators are exempted from certain financial and legal restrictions stipulated by the Public Utilities Holding Company Act of 1935.
Federal Energy Regulatory Commission (FERC)	Federal agency that regulates the price, terms, and conditions of power sold in interstate commerce and regulates the price, terms, and conditions of all transmission services owned by investor-owned utilities.
Federal Power Act (FPA)	Federal act passed in 1935 that established guidelines for federal regulations of interstate energy sales. It is the primary statute governing FERC regulation of the electricity sector.
Independent System Operator (ISO)	Independent System Operator. A neutral operator responsible for maintaining instantaneous balance of the transmission grid. The ISO performs its function by controlling the dispatch of power plants to ensure that loads match resources available to the system. The ISO generally does not own the transmission assets it controls.

Marginal Cost	In utility terms, the cost to the utility of producing the next kilowatt-hour of electricity.
Market Prices	A price set by the mutual decisions of many buyers and sellers in a competitive market.
Monopoly	A type of market with only one seller with control over market sales.
Natural Monopoly	A situation where one firm can produce a given level of output at a lower total cost than can any combination of multiple firms.
Obligation to Serve	The obligation of a utility to provide electric service within a particular boundary to any customer who seeks and is willing to pay the rates set for that service.
Open Access	All participants in the wholesale market have equal access to transmission service, as long as capacity is available, with the objective of creating a more competitive market.
Pancaked Transmission Rates	Determining the final transmission price of transporting power by adding what each transmission owner charged for transporting power over the owner's lines.
Peak Load or Peak Demand	The electric load that corresponds to the maximum level of electric demand in a specified time period.
Public Utilities Holding Company Act of 1935 (PUHCA)	Federal act which prohibits acquisition of any wholesale or retail electric business through a holding company unless that business forms part of an integrated public utility system when combined with the utility's other electric businesses.
Public Utility Regulatory Policy Act of 1978 (PURPA)	Federal act which requires utilities to buy electric power from a private qualifying facility at an avoided cost rate.
Regional Transmission Organization (RTO)	A voluntary group of transmission owners, transmission users and other entities interested in coordinating transmission planning and expansion and use on a regional or inter-regional basis. See also Independent System Operator (ISO) and transco.

Regulatory Compact	A theory which holds that, in exchange for building the generation, transmission, and distribution infrastructure necessary to fulfill an obligation to serve all customers in a franchise service area, the utility is guaranteed an opportunity to earn a return on those investments.
Reliability	Consists of the ability of the electric system to supply the aggregate electric demand and the energy requirements of the customers at all times, taking into account both scheduled and unscheduled outages of the system.
Reregulation	The design and implementation of regulatory practices to be applied to the remaining regulated entities after restructuring of the vertically integrated utility.
Restructuring	The reconfiguration of the vertically integrated electric utility.
Retail Competition	A system under which more than one electric provider can sell to retail customers.
Retail Market	A market in which electricity and other energy services are sold directly to the final customer.
Retail Wheeling	The transmission of electricity from a wholesale supplier to a retail customer by a third party.
Stranded Costs	A utility's past investment costs or contractual obligations that are not recoverable in a competitive market.
Transco	Generally, a for-profit company that is solely engaged in the transmission of bulk power.
Transition Costs	Stranded costs which are charged to a utility customer through some type of fee or surcharge.
Unbundling	Disaggregating electric utility service into its basic components and offering each component separately for sale with separate rates for each component. For example generation, transmission and distribution can be unbundled and offered as discrete services.
Vertical Integration	An arrangement whereby the same company owns all the different aspects of making, selling, and delivering a product or service.

Wheeling	The transportation of electricity over transmission lines.
Wholesale Competition	A system whereby a distributor of power would have the option to buy its power from a variety of power producers and the power producers would be able to compete to sell their power to a variety of distribution companies.
Off System Sale	Energy supplied to non-native electricity consumers.
Open Access	Enables all participants in the wholesale market equal access to transmission service, as long as capacity is available, with the objective of creating a more competitive wholesale power market. The Energy Policy Act of 1992 gave the Federal Energy Regulatory Commission (FERC) authority to order utilities to provide transmission access to third parties in the wholesale electricity market.

INTRODUCTION

This report is the culmination of a deliberative process undertaken by the Special Task Force on Electricity Restructuring. The goal of that process was to evaluate the impact of electricity restructuring on the Commonwealth of Kentucky. Briefly, restructuring is the process of "unbundling" or segmenting out the different services provided by an electric utility, determining which segments are economically competitive, and subjecting those competitive segments to the free market.[3] This is done by removing selected regulatory controls over those segments. The task force focused almost exclusively on generation or the supply segment of electric utility service.[4]

Restructuring is a complex, technical process that if undertaken would impact every customer in the Commonwealth. Changes in energy prices would impact Kentucky's businesses and industries, including those producing fuel commodities such as coal and natural gas. Restructuring also may have an impact on the environment and on related energy service industries such as heating, ventilation and cooling (HVAC), and energy management.

The impact of restructuring on consumers and electricity suppliers is more than just a price issue. Restructuring creates new rights and responsibilities. It also takes away old rights and lines of accountability. For example, restructuring gives customers the right to choose their generation supplier but confers responsibility for informed shopping on customers. In exchange for choice, utilities and regulatory commissions are no longer held accountable for many of the price and service protections afforded in a regulated market. These protections can cover a variety of things such as affordable energy prices and reasonable terms of service.

From the utility's standpoint, restructuring creates opportunities for greater profits, but also rescinds the utility's guaranteed ability to recover all prudently incurred costs. Because there is no limit on the rate of return in a competitive market, generators can earn as much profit as the market will allow. In exchange for the opportunity to earn higher profits, utility investors bear the cost of uneconomic investment decisions and poor market performance.

Even though Kentucky's current cost of producing power is the one of the lowest in the nation,[5] the issue of restructuring Kentucky's electric utility industry has taken on increased importance in recent years. Part of the importance is due to the growing number of states that have passed laws to permit retail competition. In 1996, New Hampshire, California, and Rhode Island passed laws permitting retail competition. Since then, 23 states have taken steps, either through legislation or

Public Service Commission order, to allow consumers to choose their electric supplier.[6] Most of these states have higher than average electric utility rates
.

Another reason for restructuring's growing saliency in Kentucky is that a number of surrounding states are permitting retail competition. Of the 23 states identified above, three states are in the East Central Reliability Council (ECAR) along with Kentucky. Two states are in adjoining reliability councils: Mid-Atlantic Interconnected Network (MAIN) and Southeastern Electric Reliability Council (SERC).[7] There is concern that, as the number of surrounding states permitting retail access grows, there will be increased pressure for Kentucky to restructure too. Finally, there is concern that the federal government may take action to mandate retail competition. Under this scenario, it is not clear whether Kentucky can preserve the benefits of its low-cost advantage in electricity production for Kentucky customers.

In 1998, the Kentucky General Assembly passed House Joint Resolution (HJR) 95. This resolution established a 20-member task force consisting of 10 members from the legislative branch and 10 members from the executive branch. The task force was given the task of "carefully study[ing] the issue of electricity restructuring" and analyzing restructuring's impact on Kentucky. The resolution requires the task force to issue a final report that includes both findings and recommendations to the Governor and to the Legislative Research Commission (LRC) by November 15, 1999. The submission date was extended by the LRC to December 15, 1999.

This is the final report of the task force written to satisfy the requirements imposed by HJR 95. The final report is distinct from the interim reports submitted to the task force by Resource Data International (RDI). The interim reports are the product of a collaborative effort between a research team consisting of staff from the Public Service Commission (PSC), the Legislative Research Commission (LRC), and RDI. The interim reports are considered research products produced by RDI and are not official reports of either the LRC or the PSC. Parts of the four interim reports have been excerpted and are included in this report.

The final report is based on a number of sources. Secondary sources include studies issued by federal agencies such as Energy Information Agency (EIA) and research institutes like Electric Power Research Institute (EPRI). Information from the four interim reports is used to develop detailed information on Kentucky's regulatory and market structure and as the basis for developing findings. Other sources used to develop the final report include RDI's Powerdat™ database, studies from other states, and official minutes from the task force meetings.

The structure of this report is as follows. The first chapter is comprised of five parts. Part I presents pertinent background information on electric utility restructuring, including a definition of restructuring. Part II includes a discussion

of the concept of natural monopoly as it pertains to the electric utility industry and to the development of the current regulatory regime. The third and fourth parts identify some of the challenges to the traditional view of regulating electric utilities, including state activities on electric utility restructuring. The fifth part identifies some of the concerns raised by task force members about restructuring in Kentucky.

The second chapter contains two parts. The first part describes the current market structure of Kentucky's electric utility industry, and the second part describes the current regulatory structure of Kentucky's electric utility industry. The third chapter contains the task force's findings and recommendations.

CHAPTER ONE

BACKGROUND ON ELECTRIC INDUSTRY RESTRUCTURING

Part I. Defining Restructuring

The electric utility industry is comprised of three main segments: generation, transmission, and distribution. Generation is the process of producing energy. Transmission is the process of transporting electricity across great distances on high-voltage networks. Distribution is the delivery of electricity through low-voltage lines to the ultimate consumer.

Restructuring is sometimes used interchangeably with the terms deregulation, retail access, retail wheeling, and retail competition. While each of these terms accurately describes an aspect of the restructuring process, the term "restructuring" is a more complete description of the phenomenon. For purposes of this report, electric utility restructuring is defined as a process that changes the rules which govern the different industry segments to facilitate and support market competition in only those segments that policy makers deem competitive. In this report, generation is the only segment considered potentially competitive; even though other segments such as metering and billing are potentially competitive as well.

During the restructuring process, certain segments of the industry, such as generation, are liberalized. That means barriers to competition are lifted. Other segments, such as transmission and distribution continue to be regulated. That means regulatory authority over these segments remains in force, but the specific rules that govern their primary functions may be changed.

To understand how the function of the different segments changes when the market restructures, consider the change imposed on generation, transmission, and distribution. Currently, the primary function of the generation segment is to support the regulated utility's demand for electricity within its service territory. In a restructured market, that function would change. Power suppliers would provide power to any customer that demands electricity, regardless of whether the entity is in the utility's service territory.[8] Therefore, restructuring removes barriers to trade, and subjects the generation segment to market forces.

Restructuring also reforms other segments of the industry which support the newly competitive segments. In the transmission segment, new regulations are established to prohibit transmission owners from taking actions that restrict other generators from moving their electricity from one market to another.[9] In a

restructured market, the transmission system must provide "open access" or an equal opportunity for generating utilities to utilize the transmission network. Restructuring does not make the transmission system competitive. Rather it makes the system accessible to all electricity suppliers on a comparable and equal basis so that wholesale and retail markets have enough suppliers to foster competition.

In a restructured market, distribution utilities may take on a set of new responsibilities, and may be subject to new rules of operation. For example, distribution utilities may assume the burden of tax collection for generation suppliers. Also distribution utilities may be the customer's first source of information about competitive generation suppliers in a restructured market. This fact may impose new requirements on distributors regarding the release of information about suppliers similar to those local telephone companies face regarding the release of information about competitive long-distance suppliers.

Part II. Regulation in Transition

Until the last two decades, electric generation had been considered a natural monopoly. That means it has been more efficient and less costly for a single company to supply electricity to a group of customers than for multiple companies to serve that same group.

Throughout the twentieth century, the industry was characterized by economies of scale that benefited consumers in the form of lower average costs. Average power plant size continued to grow, and due to decreasing costs for ever larger power plants, the average production costs decline. Smaller competitors could not achieve the same low cost of a very large generator.

Other factors which made electric utilities natural monopolies included uneven consumption patterns; the view of electricity as a public necessity; the expectation that capacity must be sufficient to meet peak demand, and the simultaneous dispatch and use of electricity. Consumption of electricity is uneven. Peak usage of electricity by consumers varies on a utility-by-utility basis over the summer and winter. Because electricity is a "public necessity,"[10] a utility must build enough capacity to meet peak demands even if the average duration of the peak is only a few weeks during a given season. As a result, utilities generally will have surplus capacity or under-utilized capacity. Also, unlike natural gas or propane, electricity cannot be stored and then used at some future point in time. That means when a customer turns on a switch for power, there must be enough electricity in the system to supply that marginal increase in demand. In order to maintain system reliability, there must be a constant balance between supply and demand.

This economic reality makes it very expensive for multiple suppliers to enter into the industry and compete for market share in electric generation. It also means

that the opportunity exists in a natural monopoly market for electric utilities to restrict output and reap monopoly profits. Customers are unable to find available substitutes for electricity nor can they withhold all consumption until prices fall to a level of affordability.

Concerned with maintaining reliability and protecting consumers from pricing abuses, governments imposed a "regulatory compact." In the interest of the public good, government imposed a type of economic regulation variously referred to as "cost of service," "traditional rate base," or "fair rate of return" regulation over the electric utility. In exchange, the utility was granted an "exclusive franchise area," and permitted to earn a "reasonable rate of return" on its investment.

To discourage leveraged investment by public utilities in non-utility businesses, federal laws like the Public Utility Holding Company Act of 1935 (PUCHA) forced a distinct line between regulated and nonregulated holdings. It required nonexempt holding companies to register with the Securities and Exchange Commission (SEC), which supervises and regulates the holding company system. In this regard, PUCHA encouraged vertical integration of electric utilities. PUCHA broke up the interstate holding company system and encouraged the development of a single consolidated utility serving a geographic area. PUCHA also restricted utilities to lines of business which were "essential to the operation of the utility" and prevented non-utilities from participating in the wholesale power market. In this way, PUCHA provided legal reinforcement for the argument of an electric utility as a natural monopoly.

Part III. Challenges to Electric Utility Regulation

A number of events altered the traditional view of electric generation as a natural monopoly. First, utilities are no longer isolated monopolists operating in exclusive geographic areas that are cut-off from outside markets. Greater interconnection in the transmission grid has made it possible for generators to supply power to a larger, more varied marketplace. Greater interconnection allowed utilities to sell power off-system in the wholesale market and to take advantage of the variations in demand for power both regionally and nation-wide.

Second, interconnection heightened public awareness of rate differences. Figure 1 shows that electricity rates differ sharply from state to state. Industrials were one of the first to recognize that wide variations existed both within and between states. From their standpoint, removing geographic restrictions on suppliers would offer industries the opportunity to lower their electricity costs.

The 1992 Energy Policy Act (EPAct) amended the Federal Power Act (FPA) to remove many barriers to competition among electricity suppliers in the wholesale market. While EPAct did not give FERC the authority to order retail competition, the law did not prohibit states from enacting laws to allow retail

competition. EPAct leaves the issue of whether to enact retail competition to the states.

Among other things, EPAct required utilities to provide "open access" transmission service for wholesale power transactions at cost based rates. FERC was given responsibility for implementing open access, which it did in 1996 through the issuance of FERC orders 888 and 889. FERC order 888 required investor-owned utilities that owned, controlled, or operated transmission facilities to carry any other company's power at rates that it would charge itself. Order 889 improved the operation of the wholesale electricity market by requiring utilities to make available information about transmission pricing and capacity through an electronic system known as OASIS.

Figure 1
Average Revenue from Electricity Sales to All Retail Consumers by State, 1998

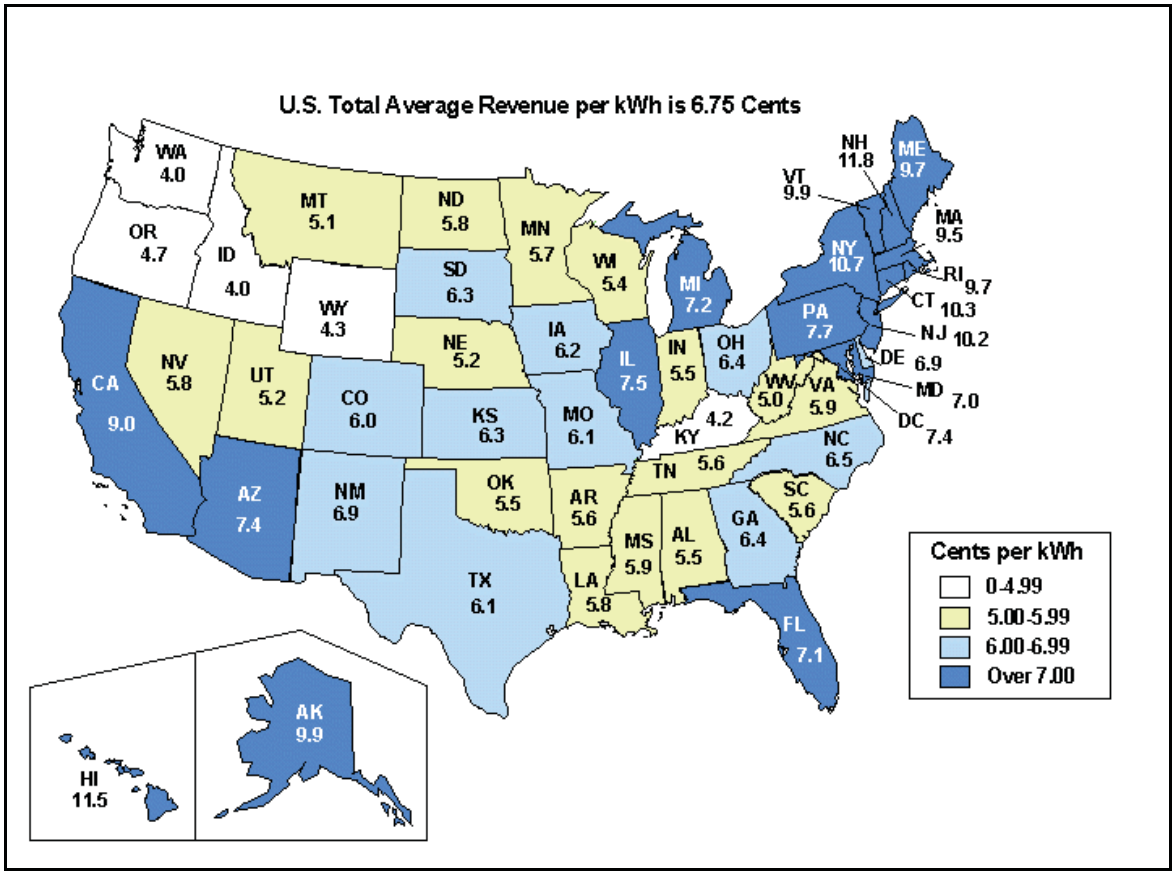


Image courtesy of Energy Information Agency.

Third, the number of suppliers in the market has grown considerably. The passage of Public Utilities Regulatory Policies Act of 1978 (PURPA) and the

Energy Policy Act of 1992 (EPAct) made it possible for new entities to acquire generation facilities and sell energy to electric utilities. PURPA created a whole new class of power producers that used co-generation or renewable energy sources called qualifying facilities (QFs). PURPA also required utilities to connect qualifying QFs to the transmission grid and to purchase QF power at the utility's "avoided cost." Avoided cost is the utility's cost of generating its own power, which it avoided when the utility purchased power from a QF. EPAct created yet another class of power producers called Exempt Wholesale Generators (EWGs). EWGs are companies that are not subject to cost of service regulation yet differ from QFs in that they are not required to use any particular generating technologies such as co-generation or renewables. EWGs expanded competition in the wholesale market by permitting a greater number of suppliers and a stronger role for market forces in setting electricity prices.

Finally, innovations in generating technologies and declining fuel costs have reduced both the investment and the operating costs of producing electric power. Over the past two decades, the efficiencies and capital costs of new gas turbines have improved substantially. The cost declines of these smaller scale power plants have brought an end to the declining marginal cost curve the industry faced during the majority of the twentieth century. Overall, fuel costs have decreased since 1996. Increased competition, efficiency improvements, and lower transportation rates have lead to reductions in coal prices. Natural gas prices have declined steadily since 1983, due in part to the partial deregulation of the natural gas industry.[11]

Part IV. Challenges from Other States

From the 1970s to the early 1990s, challenges to the traditional regulatory regime came from three principal sources: technological innovations, efficiencies in related industries, and federal law. After passage of the 1992 amendments to the Energy Policy Act and FERC's issuance of Orders 888 and 889, it became clear that retail competition would require action at the state level. As a result, the focus of attention has shifted to activities in other states.

New Hampshire was the first to adopt retail choice, quickly followed by Rhode Island and California. Since then, twenty–three states have taken steps to restructure their electricity industry. These states are Arizona, Arkansas, California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, New Mexico, Michigan, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, and Virginia. Only two states–Michigan, and New York–have enacted retail choice by order of the state's regulatory commission, which suggests that in most states legislative action was necessary to adopt retail choice.

Figure 2 shows that restructuring has occurred mostly in the higher-cost states on the west coast and eastern seaboard. Lower-cost states in the south central region have taken a slower approach. They principally are engaged in a commission or legislative investigation of retail choice.

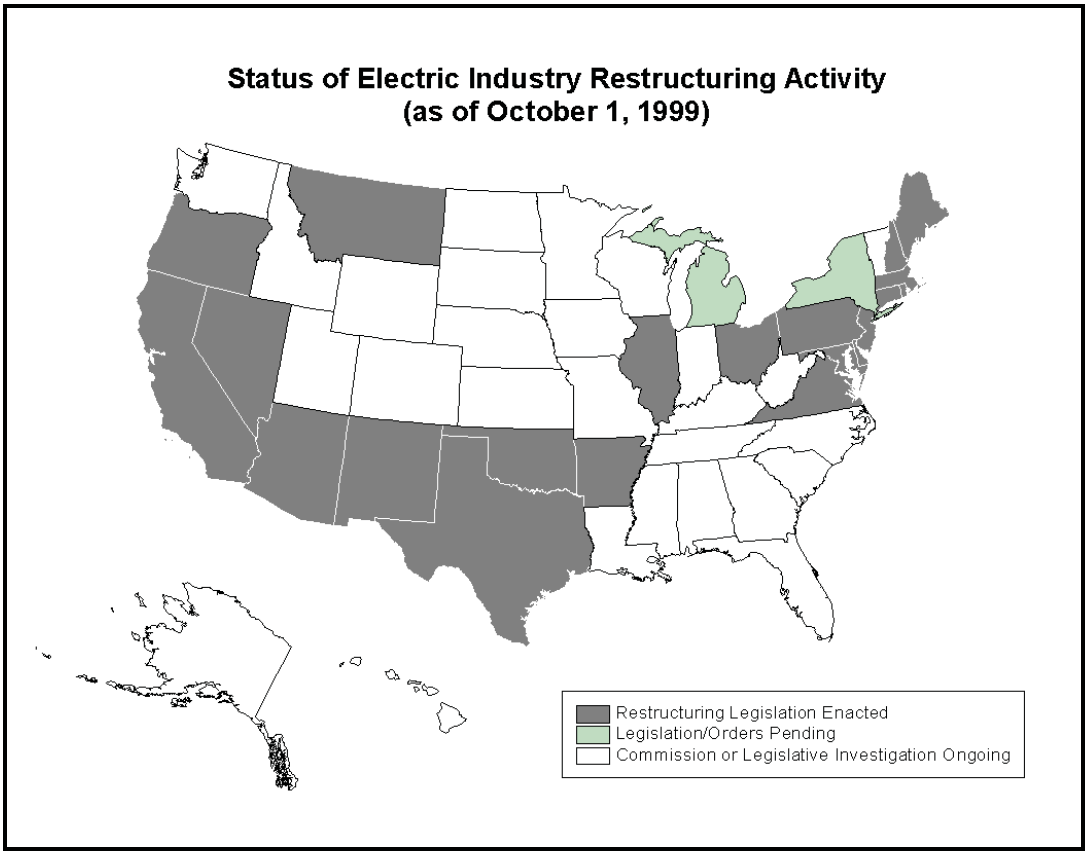
Only a handful of states have actually opened their markets. These states are California, Illinois, Massachusetts, Michigan, Montana, New Jersey, Pennsylvania, and Rhode Island.[12] With the exception of California, Massachusetts, and Rhode Island, most markets have been open less than one year, and very few reports about restructuring's impact on competition and prices are available. Some preliminary information has been compiled on two states: California and Pennsylvania. While these markets are still in a transition stage, the available information gives the indication that competition is fiercest for the industrial customers and develops faster in the more populous areas. Reassessment of the development of market competition will naturally occur as regulators, utilities, and consumers gain more experience in the marketplace.

California opened its market in May 1998. One year later, the California Public Service Commission reported that only 1.3 percent of California consumers switched electricity providers, representing approximately 10 percent of the state's total demand. The greatest number of switches occurred in the industrial and large commercial classes. As a proportion of the total switches, the fewest number of switches came from the residential customer class. Only one percent of the residential customer class switched its current generation supplier compared to 20.6 percent for the large industrials and 5.9 percent for the large commercials[13].

Pennsylvania opened their market on January 1999. The Public Utility Commission of Pennsylvania reports that 1.8 million customers registered to choose their generation supplier, but about 475,000 or 9.5 percent of eligible customers have actually switched electricity providers. The majority of those who switched are from the Philadelphia area. Pennsylvania has been lauded as one of the examples of a successful market opening.

Two states have had referenda on electricity restructuring: California and Massachusetts. Both referenda failed. California's proposition #9 did not attempt to prevent customer choice, but rather to overturn a provision in their restructuring law that securitized stranded costs. In contrast, the Massachusetts "Question 4 Deregulation Referendum" attempted to repeal Massachusetts customer choice legislation. Both were defeated.

Figure 2



Part V. Balancing Gains and Losses from Restructuring: Issues Raised in Task Force Hearings

Restructuring in the United States was first introduced in higher cost states as a way to reduce generation costs and reduce customer bills. In some cases, 80% of a customer's total bill consists of generation costs.[14] Subjecting the generation component of current rates to market forces is one method of reducing customer costs. Customers will be able to bid down the price of electricity by shopping for lower cost suppliers, and generators will find the incentive to reduce their current cost of production in order to be competitive.

Restructuring is also favored as a way to bring customer purchasing responses in line with market conditions for energy supply. As customers take a pro-active role in the marketplace, utilities will become more responsive to customer needs. Advocates of restructuring contend that utilities will make plant and infrastructure investment decisions that result in increased profits. Even more importantly, the brunt of bad investment decisions will be borne by the investors rather than by the customers.

While restructuring may have obvious benefits, task force members have expressed a number of concerns about restructuring in the Commonwealth. Some

of the concerns commonly expressed by task force members have been compiled by staff from the minutes of the official meetings and are summarized in the remainder of this section.

- Lower cost states like Kentucky may face price increases for electricity in a restructured market. This is of particular importance to Kentucky which has the third lowest rates in the nation. Interim Report No. 1, which dealt with the cost of electricity under regulation and deregulation, projects little variance between the two rates in the medium to long-term. If Kentucky chooses to restructure, policy makers must evaluate whether adding in transition charges would increase the deregulated price of electricity above the regulated rate.

- As suppliers cut costs to become more competitive, reliability of service could be undermined. The task force received testimony that indicated investment in the transmission infrastructure and in generation already has been reduced by the uncertainty inherent in the devolving marketplace. Considering the fact that the midwest faced price spikes in the summers of 1998 and 1999, it is important that Kentucky ensure adequate supplies of generation.

- Economic development in Kentucky could be compromised if restructuring leads to increased electricity rates or reduced reliability of service. Many of Kentucky's energy intensive industries have located in Kentucky because of the low cost electricity. Electricity rates are a central component of Kentucky's business recruitment and retention strategy.

- Current consumer protections may be diluted in a restructured market. Restructuring can release utilities from their obligation to serve current customers. If generators are to be competitive in a restructured market, they must be able to direct their output to a market where it will earn the most profit. If Kentucky restructures, attention must be paid to whether removing the utility's obligation to serve puts some customer segments at risk. Specific concerns that have been raised are whether low income customers will be underserved or provided service at higher rates in a restructured electricity market.

- Utilities could use revenues from regulated activities to subsidize the activities of non-regulated affiliates. There is the additional fear that the large, well financed, unregulated affiliates of regulated utilities offering products like propane, HVAC and energy efficiency will be able to drive competition out of currently competitive markets that are comprised of relatively smaller businesses. Specific attention has been focused on the use of joint marketing arrangements between the regulated utility and unregulated affiliates as well as the affiliates use of the regulated utility's name and logo.

- Maintaining and enhancing programs for low-income assistance, energy efficiency and research and development for clean coal may be reduced or eliminated entirely. Currently, programs are addressed to some degree by the electric utility industry. These programs could be placed in jeopardy under restructuring.

CHAPTER TWO

MARKET AND REGULATORY STRUCTURE OF KENTUCKY'S ELECTRIC UTILITY INDUSTRY

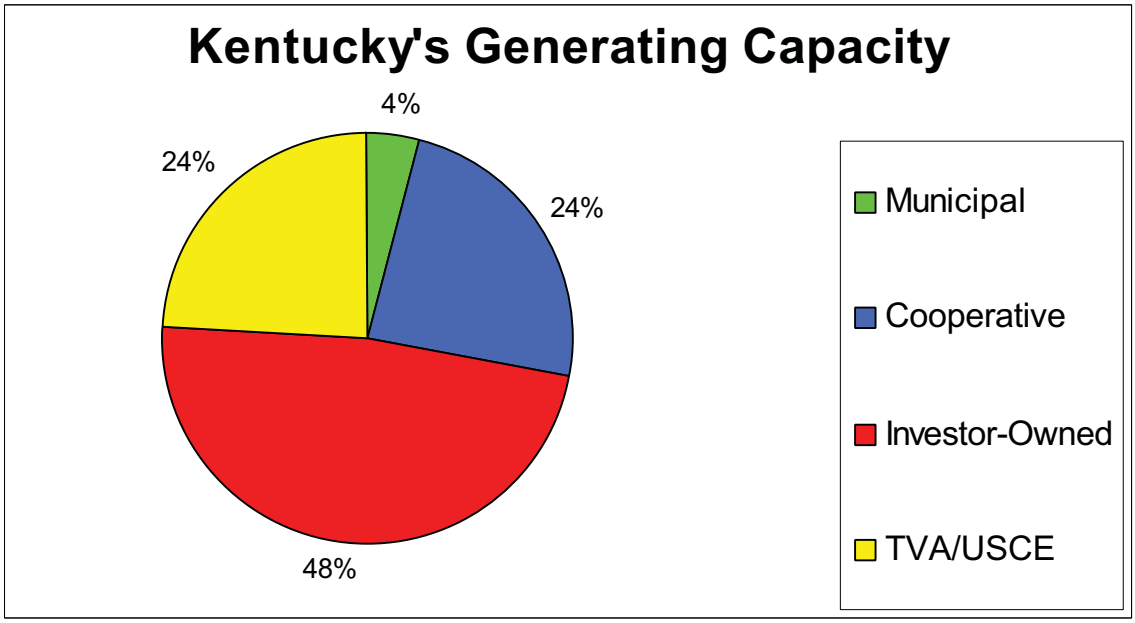
Current Market Structure of Kentucky's Electric Utility Industry

The structure of Kentucky's electric utility industry is complex. Including all federal power located in Kentucky, and the two generation and transmission cooperatives (G&Ts), and excluding Cinergy's East Bend plant,[15] Kentucky has 74 electric utilities. These utilities serve approximately four million customers at an average price of 4.02 cents. See Appendix for list of all utilities in Kentucky.

There are four major types of utilities in Kentucky: municipal, investor-owned, cooperatives, and federal power. Municipal utilities are non-profit utilities, owned and operated by a municipal government. Investor-owned utilities are for-profit utilities owned by company shareholders. Cooperatives are organized as non-profit utilities and are owned by their member customers. Federal power includes all utilities owned by the federal government.

The breakdown of utilities in Kentucky by type is as follows. Kentucky has five investor-owned utilities, 27 cooperatives, and 30 municipal utilities. Additionally, Kentucky has two sources of federal power: the Tennessee Valley Authority (TVA) and the US Army Corp. of Engineers (USCE). TVA has three generating stations in Kentucky and the USCE has three hydroelectric power stations in Kentucky. Figure 3 shows that most of the generating capacity in Kentucky is owned by the investor-owned utilities.

Figure 3



1997 Nameplate capacity excluding Cinergy's East Bend plant.
Data Source: Powerdat.

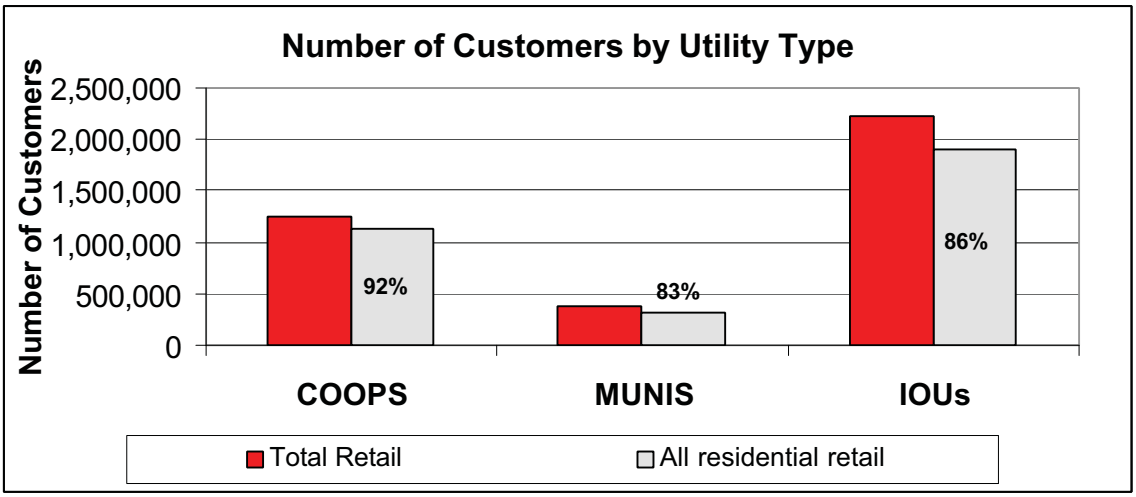
Cooperatives and municipal utilities in Kentucky primarily provide distribution services, retailing power to the ultimate consumer. Of the 30 municipals in Kentucky, only three own generation assets: City of Paris, Henderson Utility Commission (HUC), and Owensboro Municipal Utility (OMU). In addition, the municipal's share of Kentucky's generating capacity in Kentucky is relatively small. Figure 3 shows that the combined share of the generating assets owned by municipal utilities is only 4% of all the generating capacity[16] in the state.

The cooperatives own approximately 24% of the total capacity in Kentucky.[17] Like the municipals, cooperatives center their business on retailing electricity to end users, but unlike municipals, customers of cooperatives tend to be in rural areas of the state. In Kentucky, 22 of the 27 rural electric cooperatives (RECs) obtain their power exclusively through one of the two generation and transmission cooperatives (G&Ts). G&Ts are owned by and provide generation for their cooperative members. The remaining five rural cooperatives obtain their power through full-requirements contracts with TVA.

Investor-owned utilities tend to be involved in generating, transmitting, and distributing electricity. Figure 3 shows that investor-owned utilities have the largest share of Kentucky's generating capacity, roughly 48%. Only two investor-owned utilities–Berea College and Union, Light, Heat & Power–do not own generation assets in Kentucky. While IOUs do not center their activities on distribution, IOUs have a larger share of the total number of customers in the state

(See Figure 4). IOUs have twice the total number of retail customers, compared to cooperatives and municipals, because their current service territories tend to cover the more urbanized areas of the state.

Figure 4



Source: Powerdat. 1997 data for all utilities in Kentucky including those served by TVA.

Federal power also plays a significant role in Kentucky's generation market. Including USCE, federal power owns approximately 24% of the generating assets in Kentucky. Additionally, there are 253,000 residential and 44,000 commercial and industrial customers in TVA's territory.[18] This is an important fact because TVA's generation assets would not be subjected to competition and its customers would not be able to choose a generation supplier if Kentucky chose to enact retail competition. Subjecting TVA to competition would require an act by the U.S. Congress.

Current Regulatory Structure of Kentucky's Electric Utilities

Electric utilities in Kentucky are regulated by the following sources: the Federal Energy Regulatory Commission, the Kentucky Public Service Commission, local governments, and the Tennessee Valley Authority (TVA). The source of regulation varies depending on whether the entity is involved in generation, transmission, or distribution, and whether a transaction is interstate, intrastate, wholesale, or retail. It also differs depending on whether the utility is federal, municipal, investor-owned or cooperative.

The Federal Energy Regulatory Commission (FERC) has jurisdiction over the transmission of electric energy in interstate commerce and the sale of wholesale electric energy by investor-owned utilities. The FERC also has control over some intrastate retail sales such as buy-sell arrangements[19] and sales in areas designated as transmission load pockets. Federal power agencies such as TVA, municipal utilities, and electric cooperatives financed by the Rural Electric Agency (REA)

and the Rural Utility Service (RUS), formerly Rural Electrification Administration, are exempt from FERC jurisdiction.

In general terms, regulators have jurisdiction over siting and certificating transmission, distribution and generation facilities, and the regulation of utility service and rates for retail customers. These state and local-level activities are regulated by one of three sources: the Kentucky Public Service Commission, local governments, or the Tennessee Valley Authority.

The Public Service Commission's jurisdiction under KRS 278.040 extends to the retail sales and services of the state's five investor-owned utilities. Also included under PSC jurisdiction are the wholesale sales and services provided by the Big Rivers Electric Corporation and East Kentucky Power Cooperative to their 20 distribution cooperatives, as well as the retail sales and operations of those rural distribution cooperatives. Each distribution utility serves an exclusive service territory and is responsible for providing adequate, efficient, and reasonable service to customers within that territory. In general, the PSC sets the rates by which the investor-owned and cooperative utilities sell to retail customers who are the ultimate users of electricity. The Public Service Commission also sets the wholesale rates charged by Big Rivers and East Kentucky Power to their respective distribution cooperatives.

The ratemaking process is complex and time-consuming. Under KRS 278.190, the PSC has 10 months to complete a case. The process involves two basic steps. First, the Public Service Commission reviews and analyzes a utility's costs for a 12-month period to determine a reasonable level. Next, an appropriate profit level is determined. The operating expenses and profit levels are added to determine the total revenue that a utility may collect through its rates. In the second step, appropriate rates are determined for residential, commercial, and industrial customers that will produce the approved level of revenue.

The rates that a utility is authorized to charge and the rules and regulations that govern a utility's service must be printed on tariff sheets, which are filed with the PSC. These tariffs are used for every utility regulated by the PSC and are available at the Public Service Commission and the utility's office for public inspection.

To ensure that utilities provide adequate, efficient, and reasonable service, all utilities are required to file periodic reports detailing service interruptions and deficiencies. Public Service Commission staff monitor these reports for corrective actions. Staff at the PSC also conduct regular field inspections of utility facilities and records to verify compliance with PSC service standards. Customers who are dissatisfied with their service may file an informal or formal complaint with the PSC. These complaints are investigated and any service deficiencies are required to be corrected.

Municipal utilities are not considered utilities under KRS 278.010; therefore, municipals are not subject to the regulatory authority of the PSC. Municipal utilities are also exempt from regulation by the FERC. However, municipal utilities are regulated by local governments or local utility commissions, both of which have the authority to set rates and terms of service for the utility. The rates of municipals may or may not relate to the cost of providing utility service due to payments in lieu of taxes and contributions to local municipally-owned facilities and services.

One other important note of exception exists for the five cooperatives and 13 municipal utilities in Kentucky served by the TVA.[20] TVA has the authority to set rates and terms of service for any utility served by the TVA.[21] The TVA enters into full-requirements contracts with utilities inside the TVA service territory or "fence" for a period that is not to exceed twenty years. Currently, utilities served by TVA in Kentucky are under 10-year full-requirements contracts that are automatically renewed unless the utility provides TVA with a five year notice.

CHAPTER THREE

EXPECTED EFFECTS OF RESTRUCTURING IN KENTUCKY: SYNOPSIS OF RDI REPORTS TO THE TASK FORCE

Background

On December 3, 1998, the Special Task Force on Electricity Restructuring issued a Request for Proposals to obtain specialized consulting services (See Appendix C for copy of the RFP). The RFP listed seven discrete questions which were to be organized into three interim reports to the task force. At the request of RDI, the seven questions were divided into four interim reports. The questions listed in the RFP are as follows:

1. Quantify the short and long run marginal cost of electricity in Kentucky under retail competition and under the current cost of service regulation. Identify the factors that affect both short and long run marginal cost, as well as the past and anticipated volatility of any one or all of those factors.

2. Isolate factors that would contribute to a difference in the price of electricity to customers in urban and rural areas under retail competition. Generate an estimate that measures the impact that retail competition will have on the price of retail electricity sales, including generation, to urban and rural customers.

3. Describe Kentucky's current electricity trade with other states and quantify the expected impact of retail competition on Kentucky's export balance of electricity.

4. Identify the items that could potentially be the stranded costs or negative stranded costs under retail competition. Generate an estimate of positive or negative stranded costs in Kentucky.

5. Identify the factors that determine whether a provider of electricity generation can achieve market domination sufficient to distort prices. Examine these factors in the context of Kentucky's market.

6. Generate estimates that would measure the potential impact of retail competition on the future use of coal in Kentucky's fuel mix for generation, and

7. Describe the current industry structure of Kentucky's electric utilities including the growth and change in its unregulated businesses. Identify the mechanisms

by which an unregulated business could utilize assets from the regulated side of the utility to gain a competitive advantage over incumbents in the marketplace for energy-related services such as HVAC and energy efficiency.

In January, the task force hired Resource Data International (RDI) to work with a research team that consisted of staff from the Public Service Commission and staff from the Legislative Research Commission (LRC). RDI organized its research into four interim reports to the task force. The highlights of these reports are summarized briefly in this chapter. These reports are available at the LRC library or from task force staff.

Resource Data International. ***Interim. Report No. 1: Marginal Cost of Electricity and Urban/Rural Impacts in a Restructured Electric Industry*** **(Legislative Research Commission, Frankfort, Ky., 1999), photocopied.**

Brief Description of Methodologies

This interim report focuses on two questions: What is the marginal cost of electricity in a restructured electricity market, and will electricity prices in rural areas be significantly higher than electricity prices in urban areas? In order to determine the marginal cost of electricity, RDI employed a forecasting methodology. RDI created four different scenarios–basecase, high fuel cost, low-fuel cost, and technological innovation–that captured the effects of changing fuel prices and improvements in infrastructure and production costs. (For more information about RDI's methodology, please refer to RDI Interim Report No. 1.)

In order to answer the question regarding future prices of electricity in rural and urban areas, RDI isolated factors that could contribute to a rural/urban difference, examined the current rate structure for a subset of utilities across the state, and analyzed the economics of the retail supply business for electricity. (For more information about RDI's methodology, please refer to Interim Report No. 1, Chapter 5.)

Results

The results of both analyses reveal three key findings:

- Unless excess capacity exists in the market, average regulated rates in Kentucky are likely to approximate deregulated prices over the long-term. For instance, in the base case the average deregulated rate forecast is $29.0 per MWh while the average regulated rate forecast is $29.3 per MWh from 2002 through 2010. This is a difference of less than 1%. The one scenario predicting the most benefit for consumers involves rapid advances in technological innovation that reduce the cost of generation and create a period of prolonged excess capacity in the market.

- Within Kentucky, the rates of individual utilities vary widely. For instance, one higher cost utility in the state had an average price of 6.0 c/kWh in 1997 while one lower cost utility had an average price of only 3.5 c/kWh. Therefore, it is expected that over the long term, some Kentucky customers would benefit from deregulation while others will not. Customers of the lowest cost utilities are likely to experience rate increases in a deregulated market and customers of the highest cost utilities are likely to experience rate decreases.

- Price impacts, at the customer level, are determined by the current regulated rate utilities are allowed to charge for electric utility service. Differences in rural/urban electricity rates are primarily a function of the historic regulated rates charged by utilities. Due to a lack of significant transmission constraints, both urban and rural customers are expected to have access to the same wholesale price of generation service. If a customer's utility had previously had high rates in relation to the average price in Kentucky, restructuring would likely result in price declines. If their historic utility had low rates in relation to the average Kentucky rates, they would likely face price increases in a deregulated market. It is the differences in historic rates, rather than the rural vs. urban location, that will result in different impacts for different customers throughout Kentucky.

Resource Data International. ***Interim Report No. 2: Stranded Costs and Electricity Exports in a Restructured Electric Industry*** **(Legislative Research Commission, Frankfort, Ky., 1999), photocopied.**

Methodology

This report answered two questions: What are the stranded cost projections for Kentucky's utilities in a deregulated market, and how would deregulation affect Kentucky's exports of power to other states?

In order to develop stranded cost projections, RDI used an up-front administrative valuation approach to establish stranded costs associated with each utility in the state. The approach determines the value of a forecast discounted cash flow for each utility's generating asset under four different scenarios: basecase, high-cost fuel, low-cost fuel, and technological innovation. (For more information about the methodology used to determine stranded costs, please refer to Interim Report No. 2.) The asset value is then subtracted from its net book value as reported by each utility. If the utility's assets have a value higher than the book value, then the utility incurs a negative stranded cost. If the utility's asset has a value below the book value, then the utility incurs a positive stranded cost. The analysis also accounted for contractual obligations to purchase power and regulatory assets using methodologies that are similar in principal to the methodology for the generation assets.

In order to determine the impact of deregulation on Kentucky's electricity exports, RDI looked at historic net exports of electricity from Kentucky over a six year period. RDI then relied on the basecase analysis of future electricity prices in a deregulated market and information about transmission costs and constraints to determine whether it would be more profitable for Kentucky's utilities to export power outside of the state.

Key Findings

- Overall net stranded costs ranged from a negative $3.4 billion to a positive $836 million under the four different scenarios. The range of potential stranded costs is driven by assumptions regarding future fuel prices and technological innovations. These two key uncertainties will impact the price of electricity in a deregulated market. As deregulated prices increase, the value of Kentucky's coal-fired generating assets increases. As the deregulated price falls, coal-fired generating assets decrease in value.

- Union Light, Heat & Power, utilities that purchase power from TVA, and utilities that purchase power from Big Rivers Electric Cooperative are expected to face a stranded cost problem that may range from $295 million in the high price scenario to over $1 billion in the low fuel price scenario. These stranded costs are the result of long-term obligations to purchase power at prices that are expected to be above the deregulated electricity price.

- No other utility in Kentucky is expected to face stranded costs. Instead, the other utilities in the state are expected to have generating assets and purchase power contracts which are worth more in a deregulated market than in a regulated market. Negative stranded costs were forecast to range from $700 million in the technological innovation scenario to $3.7 billion in the high price scenario.

- Negative stranded costs do not imply that customers would pay more for power in a deregulated market than in a regulated market. Factors such as taxes, depreciation schedules and the cost of capital can result in negative stranded costs even though the utility's forecasted regulated rate may be slightly higher than its deregulated rate.

- The market for electricity exports from Kentucky will largely be determined by inter-regional differences in the marginal cost of producing power–not by differences in retail rates. The existence of a mature wholesale trading market in the Midwest has already served to eliminate many of the differences in the marginal production costs between utilities, limiting opportunity for exports from Kentucky. Relieving utilities of their native load obligations would not change the way they currently operate in the wholesale market.

- Exports from Kentucky to other states would not substantially change if retail wheeling were introduced. Between 2000 and 2001, exports are expected to increase modestly from a historic 7.5% of total generation to 9% of total generation. This increase is driven by the creation of a Midwest ISO. The ISO will eliminate multiple or "pancaked" transmission tariffs and replace the pancaked rates with a less expensive, "postage stamp" type rate. Between 2001 to 2010, electricity exports are expected to decrease gradually to a low of 5% of total generation as in-state generation resources are used to meet demand growth within Kentucky.

Resource Data International. ***Interim Report No. 3: Impacts of Electric Deregulation on the Kentucky Coal Industry and an Overview of Affiliate Transaction Issues*** **(Legislative Research Commission, Frankfort, Ky. 1999), photocopied.**

Methodology

This report concentrates on two questions. The first question is, what impact will deregulation have on Kentucky's coal industry? The second question addresses the risk deregulation creates for either cross-subsidization between a utility and an unregulated affiliate and negative implications for competitive markets penetrated by affiliates of electric utilities.

To answer the first question, RDI analyzed Kentucky's coal market and the factors which have led to historic declines in Kentucky's delivered cost of coal. RDI also considered the economic incentives deregulation would create for coal plant owners. (For a more complete discussion of RDI's methodology, please consult Interim Report No. 3.) To answer the second question, RDI provided an overview of the major affiliate transaction issues and discussed the policy and enforcement implications of each issue. (For more information, consult Interim Report No. 3).

Key Findings

- Deregulation is not a principal threat to Kentucky's coal industry nor is deregulation occurring in other states responsible for the downward trends in coal prices during recent years. Overall the major threats to the Kentucky coal industry continue to be traditional issues such as increased competition from Western coal markets. Western Kentucky coal has come under pressure from Power River Basin coals (PRB) from Wyoming. Stricter environmental regulations including tighter air emissions requirements have also dramatically affected Western Kentucky coal because of its higher sulfur content. Reserve depletion, higher mining costs, and reduced rail costs for cross-country

deliveries are also making it more difficult for Kentucky producers to compete on the basis of delivered price with Western coal producers.

- Any decision by Kentucky to deregulate the electric utility market will only affect 20% of Kentucky's coal industry market because only 20 percent of Kentucky's coal is sold to power producers in Kentucky. The remaining 77 percent of Kentucky's coal is sold to end users out of state.

- Deregulation is expected to intensify current competition in Kentucky's coal industry and exert downward pressure on Kentucky coal prices as electricity generators focus on bottom line profitability. Coal expenses constituted approximately 75 percent of the total fuel and operating expenses borne by coal-fired power plants in the ECAR regions during 1997. Utilities adopting cost cutting strategies are looking to eliminate or renegotiate long-term coal supply contracts and are switching to cheaper coal sources with fewer environmental costs.

- Deregulation is expected to create a strong incentive to improve unit availability and to increase generating capability at existing power stations which RDI estimates will increase demand for Kentucky coal by two to five percent over the next decade. The closure of some uneconomic nuclear power plants under deregulation will create additional demand for coal fired generation. The closure of some uneconomic coal fired plants in the United States is not expected to impact Kentucky's coal market because the plants that burn Kentucky coal tend to be economically well positioned in a deregulated market.

- In a deregulated market, several factors create the potential for utility affiliates providing non utility services to gain a competitive advantage over non-affiliated firms. First, if a vertically integrated firm, such as an electric utility, is a regulated monopolist at one level of commerce, then the firm may have an ability to project monopoly power at another level. This is of particular concern for electric utilities that own generation assets that would become competitive in a restructured market. Second, because affiliates of regulated utilities could have preferential access to critical utility facilities or information, shared governance or corporate support, and joint marketing and human resources, they may have a competitive advantage over firms not affiliated with an electric utility.

- Use of the utility logo and brand name by affiliates in advertising and marketing campaigns has proved to be the most contentious issue in other jurisdictions that are restructuring their electric utility industry or are expected to do so.

Resource Data International. ***Interim Report No. 4: Potential for Market Power Abuse in a Restructured Electricity Market*** **(Legislative Research Commission, Frankfort, Ky., 1999), photocopied.**

Methodology

RDI's final report analyzes the potential for utilities in Kentucky to increase electric generation prices above the prices that would prevail in a perfectly competitive market and enhance company profitability. The report focuses exclusively on the potential for horizontal market power, which is defined as "the ability of a single dominant firm or group of firms to profit by raising prices above competitive levels."[22]

RDI employed a four stage methodology. (For more information about the methodology employed, please consult Interim Report No. 4.) The first stage consisted of an analysis of potential barrier to entry by a competitive generation supplier over the long-term. In a second stage, RDI conducted a market share analysis to determine if any one utility in Kentucky or within one transmission interconnection of Kentucky had more than 20 percent of the generation market. In the third stage, RDI conducted a market concentration analysis which involved determining the extent to which a few firms could control prices in the short-term. In the final stage, RDI modeled potential strategic bidding strategies by firms that could posses market power using a computer simulation model.

Key Findings

- Analysis indicates that a properly functioning competitive market is expected to develop in the Midwest over the long-term. The Midwest region has limited barriers to entry that would prevent new suppliers from entering the generation market.

- With the exception of TVA and AEP, utilities in Kentucky are too small and the electricity market is sufficiently interconnected to prevent any single firm from exerting market power. Results show that in the short-term, AEP may have sufficient market presence to exert market power during peak demand conditions.

- Generators that serve load pockets[23] have the potential, if left unregulated, to exercise market power. During some demand conditions generators within a load pocket are required to run in order to meet demand. Typically, these units must run because they are either providing important ancillary services to the grid or because there is limited transmission capacity within a local area. If these units did not run, deliveries of electricity to customers would need to be curtailed because generators in load pockets are not well interconnected with the electricity grid. Alternative suppliers find it uneconomical to serve or

transmission constraints prevent supplying customers in a load pocket with generation.

- Utilities may be able to exert market power during "severe" electric conditions such as numerous unplanned generation or transmission outages. If peak demand conditions occur during these periods, it is possible for larger utilities in the state to exert market power. Over time, the ability to exert market power during severe electric conditions may be mitigated if more customers develop interruptible demand.

- Merger and acquisition activity in the U.S. is expected to continue at a rapid pace. Such consolidation in the Midwest should be closely watched as the mergers of regional utilities will only increase the ability of companies to exert market power.

- The most effective means of mitigating potential market power is divestiture of generation assets by the largest generators. However, utilities often consider retaining their generation assets paramount to their future strategic positioning.

CHAPTER FOUR

FINDINGS AND RECOMMENDATIONS

HJR 95 charges the Special Task Force on Electricity Restructuring with determining the impact of restructuring on the Commonwealth and with developing findings and recommendations. This section presents the major findings and recommendations of the task force. The findings are developed from the four RDI interim reports and expert testimony given during task force meetings.

Task Force Findings

1. There is no compelling reason at this time for Kentucky to move quickly to restructure. Despite the prospects of Congressional legislation to mandate restructuring, actions taken by 23 states to restructure, and the fact that some of those states are geographically contiguous to Kentucky, there are obvious advantages for Kentucky's adopting a wait-and-see approach to electricity restructuring. Congressional action to pass a nationwide restructuring bill appears unlikely at this time. Representatives from other states that have restructured as well as experts in the field of electricity restructuring indicate that Kentucky is in a unique position because of its existing low electricity rates, which currently are the lowest east of the Rocky Mountains. A wait-and-see approach allows Kentucky to monitor the progress of restructuring in other states and to develop options that protect Kentucky's existing low rates for electricity.

2. Restructuring is expected to have multiple effects on Kentucky's electricity prices.

   A. Restructuring would be expected to cause greater variability in electricity rates over time. If Kentucky's electricity rates are deregulated, price fluctuations would be expected to be larger in magnitude than fluctuations under cost-of-service regulation. Analysis conducted by RDI indicates that prices will increase as the amount of excess capacity in the generation market decreases. Electricity rates also were found to fluctuate in response to changes in fuel prices, particularly the cost of natural gas. Finally, RDI analysis shows that deregulated electricity prices can dramatically increase during "severe" electric conditions characterized by unplanned transmission and generation outages. During these "severe" conditions, the potential exists for utilities to raise prices above the competitive market price.

   B. Price gains from restructuring are predicated heavily upon excess generating capacity in the electricity market. In the short run, RDI analysis

shows that as excess generation capacity is reduced, the deregulated price of electricity rises, and the regulated price of electricity remains relatively unchanged. The only scenario showing sustained price reductions over the long run, even as capacity declines, occurs when improvements are made in the transmission and generation infrastructure and a reduction occurs in the utility's production costs.

C. Increases in fuel prices are expected to make electricity more costly than current, regulated prices. Conversely, a reduction in fuel prices alone is expected to make electricity prices fall in the short run. RDI's analysis shows that when gas prices are increased by twenty percent, and the market demands greater capacity reserves, the deregulated price for electricity is consistently higher than the regulated rate. When gas prices are reduced by ten percent, the electricity price is lowered only during the first three years. After the third year, the deregulated price increases to a point where both the regulated and deregulated prices converge.

D. Deregulated generation rates would be expected to vary across the state in accordance with the existing utility's current cost of producing power. Currently, the cost of generating and delivering electricity varies on a utility-by-utility basis. RDI contends that some higher-cost utilities will have to reduce their prices in order to be competitive in a deregulated market. Conversely, customers of utilities whose current cost of production is below the expected deregulated price of electricity may face price increases.

3. Restructuring is not expected to have a negative impact on electricity rates in rural areas. There are three components to the electricity bill: generation, transmission, and distribution. According to RDI analysis, customers in rural areas have traditionally had higher average electricity rates compared to customers in urban areas. The disparity in rural/urban electricity rates is primarily due to relative differences in distribution costs. However, RDI analysis shows that the cost of generation would not vary in accordance with the population density of the market. The cost of acquiring a customer in a rural area is the same as that of acquiring a customer in an urban area. Therefore, rural customers are expected to have higher distribution costs than urban customers in a restructured market, but rural customers are expected to receive the same generation price as urban customers in a restructured market.

4. Kentucky does not face sizable positive stranded costs in comparison with higher-cost states; however, Kentucky does have considerable variations in both positive and negative stranded costs on a utility-by-utility basis.

A. Positive stranded costs are comprised of purchase power contracts and are concentrated in three utilities: Cinergy's Union Light Heat & Power, Big

Rivers, and distribution utilities served by TVA. Their positive stranded costs collectively could range from $295 million to over $1 billion.[24] The remaining utilities are in a "negative stranded cost" position, which means that the market value of their generating assets and purchase power contracts is higher than the book value for these assets in a regulated market. Potential negative stranded costs in Kentucky range from nearly $700 million to $3.7 billion.[25]

B. The negative stranded cost position borne by most of the utilities in Kentucky is the result of three principal factors: lower-cost coal resources for generating stations, the lack of nuclear power in Kentucky, and the use of "construction work in progress" to finance the construction of generating stations. Construction work in progress allows the utility to charge current customers for the cost of building a power plant before the plant goes on-line.

C. The imposition of a stranded cost recovery mechanism would probably not uniformly impact all customers in Kentucky. The reason for this is two-fold: first, some Kentucky customers currently served by utilities that purchase power from TVA could not be subjected to a stranded cost recovery charge imposed by either the legislature or the PSC. TVA customers in Kentucky, who are served by utilities that have positive stranded costs, are subject to the exclusive jurisdiction of the TVA. Second, positive and negative stranded costs vary based on each utility's cost of supplying power. Therefore, the potential exists for electricity prices to rise at lower-cost utilities and fall at higher-cost utilities. If the stranded cost recovery mechanism is applied only to those customers who exit the system, existing customers of higher-cost utilities may bear a disproportionate burden for stranded costs.

5. Restructuring is not expected to negatively impact the coal industry in Kentucky. Approximately 77 percent of Kentucky's coal is sold out of state and would not be affected by a decision to restructure Kentucky's electric utility industry. The remaining 20 percent of Kentucky's coal market could be affected by a decision to restructure Kentucky's electric utility industry. But given the relatively low cost of producing power at Kentucky's coal fired generators, restructuring is not expected to reduce in-state sales of Kentucky coal. Power plants in Kentucky that use Kentucky coal are well positioned in a restructured market. Not only are Kentucky coal plants not expected to face retirement, but these plants may increase their coal utilization rates. Current declines in the production of both Western and Eastern Kentucky coal are primarily related to other factors affecting the coal industry such as stricter air emissions controls promulgated by the U.S. Environmental Protection Agency (EPA), decreasing transportation costs for coal, and price differentials between

Kentucky and coal from the western U.S., such as that of Powder River Basin (Wyoming). Restructuring is not expected to affect any of these other factors.

6. Restructuring is not expected to reduce the importance of natural gas in new generating capacity in Kentucky. Within the past ten years, all new capacity in Kentucky has been gas-fired. The last coal-fired generation unit, LG&E's Trimble County plant, came on-line during the early 1990s. As the cost advantage for gas-fired generation continues to increase, and demand for electricity continues to grow during summer peaking months, the expectation is that new capacity will be gas-fired combustion turbines. These gas units would be used exclusively for peaking purposes.

7. Restructuring is not expected to lead to dramatic outflows of Kentucky electricity to higher-cost states. Approximately 7.5 percent of Kentucky's total generation has been exported since 1995. However, RDI analysis shows that exports of electricity are expected to increase to 9 percent in the short-term if the Midwest Independent System Operator (ISO) becomes functional. This is because formation of the ISO is expected to lead to a single "postage stamp" type rate that will eliminate "pancaking" (the multiple rates charged by each transmission owner when transporting power for another supplier). RDI estimates that as demand for power grows within Kentucky, exports will decline to 5-7 percent of total generation over the long-term.

8. Absent new market rules for conduct and cost allocation between regulated utilities and unregulated affiliates, the potential exists for an uneven playing field to develop between unregulated affiliates and existing firms in competitive, unregulated product and service markets. Regulated electric utilities are reorganizing and expanding their unregulated holdings at a very rapid rate. Unregulated holdings are being concentrated in energy-related businesses such as electricity commodity sales, metering and billing, energy conservation, electrical contracting, heating, ventilation and cooling (HVAC), related fuels, and appliance repair. On a nationwide basis, unregulated businesses of regulated utilities are putting competitive pressure on existing firms. According to RDI, there is an inherent conflict in a utility's organization between the need for stricter, sometimes burdensome compliance mechanisms and the drive to succeed in newly competitive electricity markets. To prevent cross-subsidy of competitive businesses by the regulated utility and to protect customers from potential abuses of market power, some states have put restrictions on an affiliate's use of name and logo, prescribed cost allocation guidelines, established a code of conduct, and required periodic compliance audits. The Kentucky Public Service Commission is addressing these and other related issues in Administrative Case No. 369.

9. Under severe market conditions, larger utilities in Kentucky such as AEP and TVA may have significant market share and control over transmission assets to

withhold generation supplies and significantly distort electricity prices. Smaller utilities do not have the market share or control over transmission assets to withhold generation supplies and significantly distort electricity prices.

A. When a utility exerts market power, it is able to significantly increase profitability by 5 percent or more over a wide range of demand conditions. Because the East Central Area Reliability (ECAR) is comprised of a highly interconnected transmission system that poses few barriers to entry by new market entrants in generation, very few companies in Kentucky have the ability to sustain profits above those seen in a perfectly competitive market.

B. With the exception of TVA and AEP under certain limited circumstances, no utility in Kentucky currently has the potential to exert market power. However, AEP may have sufficient market presence to exercise market power during peak demand conditions. According to RDI, merger and acquisition activities are likely to continue in the future, and consolidation of existing utilities in the region does pose the threat of creating future market power situations.

C. Utilities in Kentucky may be able to exert market power in areas known as "load pockets." Load pockets constitute smaller geographic areas that are not as well interconnected to the transmission grid and sometimes arise out of unplanned transmission outages or constraints. Because competitive suppliers are unable to reach customers in the load pocket, and because there is no regulation over the generation supplier in a deregulated market, the potential exists for utilities to charge above the competitive price of electricity in that market.

Task Force Recommendations

1. The task force recommends that no action be taken during the 2000 session of the General Assembly to restructure Kentucky's electric utility industry.

2. The task force recommends that the General Assembly continue to study the issue of retail competition. The task force also recommends that the General Assembly monitor actions taken in other states that have opened their retail markets to competition and to address other issues, such as reliability of service, transmission, and consumer education. Action should be taken during the 2000 Session of the General Assembly to reauthorize the Special Task Force on Electricity Restructuring.

ENDNOTES

1 The range for positive stranded cost values is predicated on results obtained using RDI scenario analysis. For more information, please consult RDI interim report no. 2.

2. The range for negative stranded cost values is predicated on results obtained using RDI scenario analysis. For more information, please consult RDI interim report no. 2.

3. A more thorough theoretical discussion of restructuring is presented in Chapter One of this report.

4. There are three segments of electric service: generation, transmission, and distribution.

5. In 1999, Kentucky's average revenue per kilowatt-hour was $4.02. Only two other states, Idaho and Washington, have average revenues lower than Kentucky's, due in part to access to lower-cost hydroelectric power. For more information see EIA *Electric Sales and Revenue 1998*, December 1999. Average revenue for all classes of customers. Average revenue is not equal to the average rate. It is a widely accepted proxy used for determining the rate for a regulated utility.

6. States which allow retail choice are: Arizona, Arkansas, California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, and Virginia.

7. Michigan, Ohio, and part of Virginia are in the East Central Area Reliability Council. Illinois and the remaining part of Virginia are in adjoining reliability councils. A reliability council consist of representatives from utilities that own transmission located within the geographic territory of the council. The reliability council is responsible for planning and operations activities for the interconnected transmission system for the purposes of maintaining reliability in the wholesale power market.

8. Because restructuring may remove the utility's obligation to serve its native customers, utilities may also retain the right to refuse to sell power to some customers even if those customers demand power.

9. Federal Energy Regulatory Commission, Order No. 888, Final Rule issued on April 24, 1996 (Docket Nos. RM95-8-000, Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities).

10. Theories of public utility argue that an entity becomes a "public utility"when the service or output is vital for the welfare or future growth of a society. For more information see James C. Bonbright et al., *Principles of Public Utility Rates* (Arlington, VA: Public Utilities Reports, Inc. 1988), pp. 14-16.

11. *Challenges of the Electric Power Industry Restructuring for Fuel Suppliers*, Energy Information Agency DOE/EIA-0623(98), (Washington, DC: September 1998), pp. 3-4.

12. California's market opened on 3/98. Non-residential consumers began customer choice on 10/99. Massachusetts' retail access program began on 3/98. Select utilities began offering choice to large industrial customers in Michigan on 6/1/99. Large customers were able to choose in Montana on 7/1/98. New Jersey's retail choice program opened for all consumers on 8/1/99. Pennsylvania's customer choice program opened January 1, 1999, with two-thirds of the customers having retail access. Rhode Island Commenced customer choice in June 1999.

13. Current information about customer choice programs is available on-line at Energy Information Agency at http://www.eia.doe.gov/cneaf/electricity/chg_str/retail.html.

14. For more information see Interim Report No. 1.

15. Although Cinergy's East Bend plant is physically located in Kentucky, this plant is treated as an Ohio plant

16. Generating capacity is the nameplate capacity for each plant in Kentucky reported in 1998 to EIA. Source RDI Powerdat.

17. One caveat applies. Big Rivers filed for Chapter 11 Bankruptcy on September 25, 1996. The US Bankruptcy Court for the Western District of Kentucky confirmed a Plan of Reorganization proposed by Big Rivers. This plan contains a 25-year lease agreement between Big Rivers and LG&E Energy Corp. Under the agreement, Big Rivers continues to be owned by its cooperative membership, but has a 20-year lease arrangement with LG&E Energy Corp. and some of its unregulated affiliates. In brief, this arrangement gives LG&E the right to operate their assets and market the power generated from those assets.

18. Information provided to the task force staff by TVA.

19. A power buy-back occurs when an end user purchases power from a third party, resells it to a utility and then buys it back from the utility.

20. Cooperatives with service territory in Kentucky served by TVA include the following: Hickman-Fulton RECC, Pennyrile RECC, Warren Rural Electric Coop. Corp., West Kentucky RECC, Tri-County Electric Cooperative. Municipals in Kentucky served by TVA include Benton Electric & Gas, Bowling Green Municipal Utilities, Franklin Electric Plant Board, Fulton Electric & Gas Systems, Glasgow Electric Plant Board, Hickman Electric & Gas Systems, Hopkinsville Electric System, Mayfield Electric & Water Systems, Monticello Electric Plant Board, Murray Electric & Natural Gas Systems, Paducah Power System, Princeton Electric Plant Board, Russellville Electric Plant Board.

21. See Title 16 U.S.C. § 831(i) (1998).

22. Resource Data International. *Interim Report No. 4: Potential for Market Power Abuse in a Restructured Electricity Market (*Legislative Research Commission, Frankfort, KY., 1999), photocopied. p. 3.

23. A load pocket is a geographic market that is relatively small and cannot be served by other suppliers due to a lack of transmission interconnection or transmission constraints.

24. The range for positive stranded cost values is predicated on results obtained using RDI scenario analysis. For more information, please consult RDI interim report no. 2.

25. The range for negative stranded cost values is predicated on results obtained using RDI scenario analysis. For more information, please consult RDI interim report no. 2.

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APPENDIX A-1

OVERVIEW OF ELECTRIC UTILITIES IN KENTUCKY

(by Class of Ownership, Number of Customers, Revenue, Sales and Average Revenue per kilowatt-hour for Residential Customers Only)

Utility	Class of Ownership	Number of Customers	Revenue ($000s)	kWh Sales (000s)	Average Revenue per kWh
Barbourville City of	Publicly Owned	3,280	1,812	34,787	5.21
Bardstown City of	Publicly Owned	2,972	1,921	38,464	4.99
Bardwell City of	Publicly Owned	470	276	4,760	5.80
Benham City of	Publicly Owned	294	223	4,835	4.61
Benton City of	Publicly Owned	1,815	1,734	24,494	7.08
Berea College	Investor-Owned	3,660	1,972	42,623	4.63
Big Sandy Rural Elec Coop Corp	Cooperative	10,838	8,155	153,025	5.33
Blue Grass Energy Coop Corp	Cooperative	29,546	23,764	423,435	5.61
Bowling Green City of	Publicly Owned	19,341	14,016	216,275	6.48
Clark Energy Coop Inc	Cooperative	20,622	14,827	234,698	6.32
Corbin City Utilities Comm	Publicly Owned	3,175	1,826	33,996	5.37
Cumberland Valley Rural E C C	Cooperative	19,176	13,566	255,146	5.32
Falmouth City of	Publicly Owned	1,148	691	10,323	6.69
Farmers Rural Elec Coop Corp	Cooperative	19,164	13,776	252,577	5.45
Fleming-Mason Rural E C C	Cooperative	18,645	11,840	213,152	5.55
Frankfort City of	Publicly Owned	15,816	8,277	188,919	4.38
Franklin City of	Publicly Owned	3,815	2,788	45,986	6.06
Fulton City of	Publicly Owned	1,552	1,213	19,094	6.35
Glasgow City of	Publicly Owned	4,974	3,824	59,077	6.47
Grayson Rural Elec Coop Corp	Cooperative	12,424	8,976	144,608	6.21
Green River Electric Corp	Cooperative	25,380	23,607	373,963	6.31
Harrison County Rural E C C	Cooperative	11,913	9,416	141,285	6.66
Henderson City Utility Comm	Publicly Owned	9,652	4,653	112,091	4.15
Henderson-Union Elec Coop Corp	Cooperative	16,699	15,172	235,564	6.44
Hickman City of	Publicly Owned	1,049	951	12,838	7.41
Hickman-Fulton Counties RECC	Cooperative	3,037	3,327	46,682	7.13
Hopkinsville City of	Publicly Owned	11,386	7,988	136,292	5.86
Inter County Rural E C C	Cooperative	20,185	16,485	272,078	6.06
Jackson Energy Coop Corp	Cooperative	41,710	32,521	555,943	5.85
Jackson Purchase Energy CC	Cooperative	23,056	21,583	340,818	6.33
Jellico City of	Publicly Owned	1,950	1,640	23,466	6.99
Kentucky Power Co	Investor-Owned	142,783	104,706	2,156,126	4.86
Kentucky Utilities Co	Investor-Owned	368,338	220,791	4,883,616	4.52
Licking Valley Rural E C C	Cooperative	14,341	9,696	164,521	5.89
Louisville Gas & Electric Co	Investor-Owned	315,886	213,476	3,533,794	6.04
Madisonville Municipal Utils	Publicly Owned	7,125	3,672	76,280	4.81
Mayfield City of	Publicly Owned	4,860	3,704	56,183	6.59
Meade County Rural E C C	Cooperative	21,460	15,344	242,564	6.33
Monticello City of	Publicly Owned	2,745	2,153	35,417	6.08
Murray City of	Publicly Owned	5,680	4,529	74,594	6.07
Nicholasville City of	Publicly Owned	4,698	2,527	55,278	4.57

Appendix A-1 Contd.

Nolin Rural Electric Coop Corp	Cooperative	23,551	19,450	350,905	5.54
Olive Hill City of	Publicly Owned	1,124	697	12,765	5.46
Owen Electric Coop Inc	Cooperative	38,941	29,915	479,197	6.24
Owensboro City of	Publicly Owned	22,198	12,027	235,188	5.11
Paducah City of	Publicly Owned	18,892	14,084	227,803	6.18
Paris City of	Publicly Owned	2,103	886	20,607	4.30
Pennyrile Rural Elec Coop Corp	Cooperative	32,780	32,928	472,438	6.97
Princeton City of	Publicly Owned	3,250	2,409	33,501	7.19
Providence City of	Publicly Owned	1,519	1,093	17,563	6.22
Russellville City of	Publicly Owned	3,332	2,415	37,038	6.52
Salt River Electric Coop Corp	Cooperative	30,685	25,770	467,565	5.51
Shelby Energy Co-op Inc	Cooperative	11,579	9,785	160,390	6.10
South Kentucky Rural E C C	Cooperative	49,172	33,214	588,592	5.64
Taylor County Rural E C C	Cooperative	18,875	13,947	242,989	5.74
Tri-County Elec Member Corp	Cooperative	18,213	16,034	241,806	6.63
Union Light Heat & Power Co	Investor-Owned	106,433	71,544	1,048,516	6.82
Vanceburg City of	Publicly Owned	2,355	1,610	27,598	5.83
Warren Rural Elec Coop Corp	Cooperative	42,773	42,837	633,449	6.76
West Kentucky Rural E C C	Cooperative	29,758	31,043	429,458	7.23
Williamstown Utility Comm	Publicly Owned	1,161	819	12,370	6.62
State Total		1,705,354	1,215,925	21,669,405	5.61

Source: Energy Information Agency, Electric Sales and Revenue, 1998. Table 14.

APPENDIX A-2

OVERVIEW OF ELECTRIC UTILITIES IN KENTUCKY

(by Class of Ownership, Number of Customers, Revenue, Sales and Average Revenue per kilowatt-hour for Residential Customers Only)

Utility	Class of Ownership	Number of Customers	Revenue ($000s)	Sales (000s kWh)	Average Revenue per kWh
Barbourville City of	Publicly Owned	461	441	6,883	6.41
Bardstown City of	Publicly Owned	901	2,703	55,912	4.83
Bardwell City of	Publicly Owned	83	155	2,666	5.81
Benham City of	Publicly Owned	12	29	521	N/A
Benton City of	Publicly Owned	537	2,004	30,409	6.59
Berea College	Investor-Owned	723	1,129	21,822	5.17
Big Sandy Rural Elec Coop Corp	Cooperative	855	2,723	51,790	5.26
Blue Grass Energy Coop Corp	Cooperative	1,191	4,437	83,482	5.31
Bowling Green City of	Publicly Owned	3,709	20,496	328,489	6.24
Clark Energy Coop Inc	Cooperative	1,260	5,078	78,457	6.47
Corbin City Utilities Comm	Publicly Owned	590	880	14,823	5.94
Cumberland Valley Rural E C C	Cooperative	1,132	1,176	16,980	6.93
Falmouth City of	Publicly Owned	69	362	5,408	6.69
Farmers Rural Elec Coop Corp	Cooperative	1,080	2,936	56,236	5.22
Fleming-Mason Rural E C C	Cooperative	1,158	4,111	84,219	4.88
Frankfort City of	Publicly Owned	2,533	3,414	69,180	4.93
Franklin City of	Publicly Owned	681	2,453	40,015	6.13
Fulton City of	Publicly Owned	329	1,473	23,284	6.33
Glasgow City of	Publicly Owned	1,494	6,731	105,797	6.36
Grayson Rural Elec Coop Corp	Cooperative	1,132	2,238	36,269	6.17
Green River Electric Corp	Cooperative	3,781	4,154	65,927	6.30
Harrison County Rural E C C	Cooperative	265	818	13,711	5.97
Henderson City Utility Comm	Publicly Owned	1,666	6,825	185,789	3.67
Henderson-Union Elec Coop Corp	Cooperative	1,397	4,399	68,331	6.44
Hickman City of	Publicly Owned	239	798	8,982	8.88
Hickman-Fulton Counties RECC	Cooperative	643	1,136	13,862	8.20
Hopkinsville City of	Publicly Owned	1,973	8,812	145,235	6.07
Inter County Rural E C C	Cooperative	473	1,745	29,250	5.97
Jackson Energy Coop Corp	Cooperative	2,460	2,870	45,957	6.24
Jackson Purchase Energy CC	Cooperative	2,188	7,812	145,826	5.36
Jellico City of	Publicly Owned	239	358	4,161	8.60
Kentucky Power Co	Investor-Owned	24,312	60,115	1,194,520	5.03
Kentucky Utilities Co	Investor-Owned	64,987	149,519	3,465,490	4.31
Licking Valley Rural E C C	Cooperative	938	2,455	38,697	6.34
Louisville Gas & Electric Co	Investor-Owned	37,274	170,954	3,132,436	5.46
Madisonville Municipal Utils	Publicly Owned	1,392	9,616	226,076	4.25
Mayfield City of	Publicly Owned	919	4,386	68,697	6.38
Meade County Rural E C C	Cooperative	1,598	5,128	75,467	6.80
Monticello City of	Publicly Owned	582	2,324	35,386	6.57
Murray City of	Publicly Owned	1,113	4,097	66,567	6.15
Nicholasville City of	Publicly Owned	440	1,110	22,690	4.89

Appendix A-2 Contd.

Nolin Rural Electric Coop Corp	Cooperative	1,066	4,561	87,882	5.19
Olive Hill City of	Publicly Owned	220	545	10,116	5.39
Owen Electric Coop Inc	Cooperative	1,264	6,151	113,645	5.41
Owensboro City of	Publicly Owned	2,465	2,299	43,964	5.23
Paducah City of	Publicly Owned	3,049	16,749	256,480	6.53
Paris City of	Publicly Owned	298	353	7,009	5.04
Pennyrile Rural Elec Coop Corp	Cooperative	7,871	16,954	221,077	7.67
Princeton City of	Publicly Owned	643	2,469	34,604	7.14
Providence City of	Publicly Owned	205	782	16,051	4.87
Russellville City of	Publicly Owned	715	3,277	49,937	6.56
Salt River Electric Coop Corp	Cooperative	1,537	1,746	28,215	6.19
Shelby Energy Co-op Inc	Cooperative	318	2,559	51,463	4.97
South Kentucky Rural E C C	Cooperative	2,876	3,091	50,712	6.10
Taylor County Rural E C C	Cooperative	2,093	4,021	75,379	5.33
Tri-County Elec Member Corp	Cooperative	4,494	9,277	129,841	7.14
Union Light Heat & Power Co	Investor-Owned	11,201	55,528	976,613	5.69
Vanceburg City of	Publicly Owned	294	599	10,349	5.79
Warren Rural Elec Coop Corp	Cooperative	6,340	18,440	258,099	7.14
West Kentucky Rural E C C	Cooperative	5,064	10,189	129,101	7.89
Williamstown Utility Comm	Publicly Owned	243	880	12,564	7.00
State Total		221,065	674,870	12,728,800	5.30

Source: Energy Information Agency, Electric Sales and Revenue, 1998. Table 14.

APPENDIX A-3

OVERVIEW OF ELECTRIC UTILITIES IN KENTUCKY

(by Class of Ownership, Number of Customers, Revenue, Sales and Average Revenue per kilowatt-hour for Industrial Customers Only)

Utility	Class of Ownership	Number of Customers	Revenue ($000s)	kWh Sales (000s)	Average Revenue per kWh
Barbourville City of	Publicly Owned	155	2,200	43,879	5.01
Bardstown City of	Publicly Owned	9	2,834	70,571	4.02
Bardwell City of	Publicly Owned	N/A	N/A	N/A	N/A
Benham City of	Publicly Owned	N/A	N/A	N/A	N/A
Benton City of	Publicly Owned	1	383	6,392	5.99
Berea College	Investor-Owned	47	2,496	55,799	4.47
Big Sandy Rural Elec Coop Corp	Cooperative	3	825	18,281	4.51
Blue Grass Energy Coop Corp	Cooperative	12	5,434	155,737	3.49
Bowling Green City of	Publicly Owned	16	9,531	187,401	5.09
Clark Energy Coop Inc	Cooperative	1	98	1,717	N/A
Corbin City Utilities Comm	Publicly Owned	42	555	16,948	3.27
Cumberland Valley Rural E C C	Cooperative	82	7,195	173,003	4.16
Falmouth City of	Publicly Owned	4	45	655	N/A
Farmers Rural Elec Coop Corp	Cooperative	5	2,882	63,227	4.56
Fleming-Mason Rural E C C	Cooperative	3	9,964	357,093	2.79
Frankfort City of	Publicly Owned	250	13,409	390,518	3.43
Franklin City of	Publicly Owned	7	6,188	146,762	4.22
Fulton City of	Publicly Owned	4	1,297	23,958	5.41
Glasgow City of	Publicly Owned	10	8,060	169,094	4.77
Grayson Rural Elec Coop Corp	Cooperative	1	648	18,502	3.50
Green River Electric Corp	Cooperative	266	116,034	4,337,086	2.68
Harrison County Rural E C C	Cooperative	1	1,678	51,034	3.29
Henderson City Utility Comm	Publicly Owned	15	8,180	270,442	3.02
Henderson-Union Elec Coop Corp	Cooperative	21	63,385	2,302,991	2.75
Hickman City of	Publicly Owned	N/A	N/A	N/A	N/A
Hickman-Fulton Counties RECC	Cooperative	3	2,852	60,040	4.75
Hopkinsville City of	Publicly Owned	7	5,161	138,102	3.74
Inter County Rural E C C	Cooperative	1	522	13,025	4.01
Jackson Energy Coop Corp	Cooperative	151	6,638	148,242	4.48
Jackson Purchase Energy CC	Cooperative	9	3,586	90,756	3.95
Jellico City of	Publicly Owned	N/A	N/A	N/A	N/A
Kentucky Power Co	Investor-Owned	1,654	94,186	3,130,767	3.01
Kentucky Utilities Co	Investor-Owned	2,025	177,340	5,374,625	3.30
Licking Valley Rural E C C	Cooperative	4	663	14,949	4.44
Louisville Gas & Electric Co	Investor-Owned	424	113,372	3,097,202	3.66
Madisonville Municipal Utils	Publicly Owned	N/A	N/A	N/A	N/A
Mayfield City of	Publicly Owned	3	1,626	26,490	6.14
Meade County Rural E C C	Cooperative	N/A	N/A	N/A	N/A
Monticello City of	Publicly Owned	2	977	19,944	4.90
Murray City of	Publicly Owned	6	5,924	114,287	5.18
Nicholasville City of	Publicly Owned	4	2,254	70,222	3.21

Appendix A-3 Contd.

Nolin Rural Electric Coop Corp	Cooperative	5	3,967	126,819	3.13
Olive Hill City of	Publicly Owned	N/A	N/A	N/A	N/A
Owen Electric Coop Inc	Cooperative	12	20,831	728,360	2.86
Owensboro City of	Publicly Owned	524	16,951	494,885	3.43
Paducah City of	Publicly Owned	9	4,475	82,502	5.42
Paris City of	Publicly Owned	22	327	8,843	3.70
Pennyrile Rural Elec Coop Corp	Cooperative	21	11,398	212,938	5.35
Princeton City of	Publicly Owned	3	1,616	25,379	6.37
Providence City of	Publicly Owned	N/A	N/A	N/A	N/A
Russellville City of	Publicly Owned	4	2,626	50,284	5.22
Salt River Electric Coop Corp	Cooperative	228	6,189	143,334	4.32
Shelby Energy Co-op Inc	Cooperative	10	4,836	136,010	3.56
South Kentucky Rural E C C	Cooperative	294	7,885	169,388	4.65
Taylor County Rural E C C	Cooperative	7	567	9,842	5.76
Tri-County Elec Member Corp	Cooperative	7	6,753	133,769	5.05
Union Light Heat & Power Co	Investor-Owned	400	43,794	1,048,912	4.18
Vanceburg City of	Publicly Owned	6	298	5,276	5.65
Warren Rural Elec Coop Corp	Cooperative	30	16,971	347,546	4.88
West Kentucky Rural E C C	Cooperative	6	8,926	215,419	4.14
Williamstown Utility Comm	Publicly Owned	9	886	26,621	3.33
State Total		6,864	1,115,024	38,259,679	2.91

Source: Energy Information Agency, Electric Sales and Revenue, 1998. Table 15.

APPENDIX A-4

OVERVIEW OF ELECTRIC UTILITIES IN KENTUCKY

(by Class of Ownership, Number of Customers, Revenue, Sales and Average Revenue per kilowatt-hour for All Customer)

Utility	Class of Ownership	Number of Customers	Revenue ($000s)	kWh Sales (000s)	Average Revenue per kWh
Barbourville City of	Publicly Owned	3,897	4,516	88,799	5.09
Bardstown City of	Publicly Owned	4,309	7,491	165,331	4.53
Bardwell City of	Publicly Owned	584	478	8,097	5.90
Benham City of	Publicly Owned	312	284	5,886	4.83
Benton City of	Publicly Owned	2,355	4,205	62,707	6.71
Berea College	Investor-Owned	4,431	5,684	121,454	4.68
Big Sandy Rural Elec Coop Corp	Cooperative	11,696	11,703	223,096	5.25
Blue Grass Energy Coop Corp	Cooperative	30,774	33,743	663,269	5.09
Bowling Green City of	Publicly Owned	23,211	44,741	740,596	6.04
Clark Energy Coop Inc	Cooperative	21,901	20,046	315,476	6.35
Corbin City Utilities Comm	Publicly Owned	3,807	3,261	65,767	4.96
Cumberland Valley Rural E C C	Cooperative	20,390	21,937	445,129	4.93
Falmouth City of	Publicly Owned	1,221	1,098	16,386	6.70
Farmers Rural Elec Coop Corp	Cooperative	20,256	19,622	372,381	5.27
Fleming-Mason Rural E C C	Cooperative	19,809	25,922	654,537	3.96
Frankfort City of	Publicly Owned	19,334	26,372	677,085	3.89
Franklin City of	Publicly Owned	4,533	11,574	234,790	4.93
Fulton City of	Publicly Owned	1,903	4,059	67,437	6.02
Glasgow City of	Publicly Owned	6,525	18,941	337,492	5.61
Grayson Rural Elec Coop Corp	Cooperative	13,558	11,868	199,452	5.95
Green River Electric Corp	Cooperative	30,043	146,330	4,815,799	3.04
Harrison County Rural E C C	Cooperative	12,179	11,912	206,030	5.78
Henderson City Utility Comm	Publicly Owned	12,891	20,144	579,318	3.48
Henderson-Union Elec Coop Corp	Cooperative	18,125	82,964	2,607,025	3.18
Hickman City of	Publicly Owned	1,295	1,804	22,487	8.02
Hickman-Fulton Counties RECC	Cooperative	3,686	7,418	121,769	6.09
Hopkinsville City of	Publicly Owned	13,394	22,473	425,812	5.28
Inter County Rural E C C	Cooperative	20,659	18,752	314,353	5.97
Jackson Energy Coop Corp	Cooperative	45,050	42,851	765,394	5.60
Jackson Purchase Energy CC	Cooperative	25,267	33,044	577,923	5.72
Jellico City of	Publicly Owned	2,194	2,066	28,242	7.32
Kentucky Power Co	Investor-Owned	169,249	259,884	6,491,942	4.00
Kentucky Utilities Co	Investor-Owned	443,443	603,762	15,096,386	4.00
Licking Valley Rural E C C	Cooperative	15,283	12,814	218,167	5.87
Louisville Gas & Electric Co	Investor-Owned	359,291	552,877	10,903,610	5.07
Madisonville Municipal Utils	Publicly Owned	8,517	13,288	302,356	4.39
Mayfield City of	Publicly Owned	5,830	9,881	153,758	6.43
Meade County Rural E C C	Cooperative	23,064	20,528	318,916	6.44
Monticello City of	Publicly Owned	3,351	5,554	92,247	6.02
Murray City of	Publicly Owned	6,812	14,742	257,811	5.72
Nicholasville City of	Publicly Owned	5,143	5,972	149,614	3.99

Appendix A-4 Contd.

Nolin Rural Electric Coop Corp	Cooperative	24,643	28,044	566,677	4.95
Olive Hill City of	Publicly Owned	1,344	1,242	22,881	5.43
Owen Electric Coop Inc	Cooperative	40,449	57,485	1,330,777	4.32
Owensboro City of	Publicly Owned	25,190	32,702	832,717	3.93
Paducah City of	Publicly Owned	22,405	36,240	577,166	6.28
Paris City of	Publicly Owned	2,545	1,627	37,336	4.36
Pennyrile Rural Elec Coop Corp	Cooperative	40,827	62,262	919,183	6.77
Princeton City of	Publicly Owned	3,913	6,646	95,784	6.94
Providence City of	Publicly Owned	1,724	1,875	33,614	5.58
Russellville City of	Publicly Owned	4,103	8,465	139,337	6.08
Salt River Electric Coop Corp	Cooperative	32,614	33,847	640,615	5.28
Shelby Energy Co-op Inc	Cooperative	11,916	17,187	347,911	4.94
South Kentucky Rural E C C	Cooperative	52,967	44,673	817,244	5.47
Taylor County Rural E C C	Cooperative	20,982	18,554	328,476	5.65
Tri-County Elec Member Corp	Cooperative	22,909	32,708	512,648	6.38
Union Light Heat & Power Co	Investor-Owned	119,046	189,919	3,432,468	5.53
Vanceburg City of	Publicly Owned	2,655	2,507	43,223	5.80
Warren Rural Elec Coop Corp	Cooperative	49,363	79,689	1,254,626	6.35
West Kentucky Rural E C C	Cooperative	34,901	51,092	785,008	6.51
Williamstown Utility Comm	Publicly Owned	1,413	2,585	51,555	5.01
State Total		1,955,504	3,154,844	75,850,311	4.16

Source: Energy Information Agency, Electric Sales and Revenue, 1998. Table 16.

APPENDIX B

HOUSE JOINT RESOLUTION 95

A JOINT RESOLUTION directing a study of electric restructuring during the 1998-2000 legislative interim, and making an appropriation therefor.

WHEREAS, electricity is a pervasive force and vital need in the current economy of Kentucky; and

WHEREAS, Kentucky enjoys among the lowest electric utility rates in the nation, benefiting not only citizen ratepayers but also allowing the state to use this as a tool in recruiting business; and

WHEREAS, restructuring the electric industry would have profound impacts upon the overall economy of Kentucky; and

WHEREAS, restructuring and deregulation have yielded tangible benefits in the airline, trucking, and telecommunications industries; and

WHEREAS, several states have begun to restructure their electric delivery systems in the hopes of lowering electric utility rates, and the United States Congress also has begun to debate the issue; and

WHEREAS, any restructuring in Kentucky must guarantee universal quality service, with adequate consumer education, and should take into account any possible impacts upon Kentucky coal as a viable generation source; and

WHEREAS, the issue of electricity restructuring is a complex one deserving of intensive study and careful, prudent recommendations;

NOW, THEREFORE,

Be it resolved by the General Assembly of the Commonwealth of Kentucky:

Section 1. There is established the Electricity Restructuring Task Force, whose membership shall carefully study the issue of electric restructuring in Kentucky during the 1998-2000 interim and analyze its impacts upon the Commonwealth. The task force shall meet at least monthly, beginning not later than October 1, 1998, and shall report back to the Legislative Research Commission and the Governor with findings and recommendations no later than November 15, 1999.

Section 2.

(1) The task force shall be comprised of the following members:

(a) Ten members from the executive branch, to be appointed by the Governor, with one member being the Attorney General or his designee; and

(b) Ten members from the General Assembly, of which three members shall be appointed by the President of the Senate, three members shall be appointed by the Speaker of the House, two members shall be appointed by the Senate Minority Floor Leader, and two members shall be appointed by the House Minority Floor Leader. All legislative branch appointments shall be approved by the Legislative Research Commission.

(2) The task force shall have three co-chairs, one appointed by the Governor, one appointed by the President of the Senate, and one appointed by the Speaker of the House. All appointments shall be made before July 31, 1998, and all legislative appointments shall be approved by the Legislative Research Commission

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Section 3. The task force may form advisory committees of no more than seven persons. These advisory committees may contain representatives of the private sector, but

in all cases the membership of an advisory committee shall consist of more task force members than private sector representatives. Advisory committees may study particular areas of interest to the task force, such as universal service, consumer education, reliability, and future regulation. The sole role of an advisory committee shall be to report back to the full task force.

Section 4. Except as provided in KRS 18A.200, members of the task force, shall receive actual travel expenses while attending meetings.

Section 5. The task force may employ consultants, request and hear testimony, or take any necessary steps to ensure a fair, thorough, and reasonable study of the issue. The task force shall receive staffing assistance from the Public Service Commission and the Legislative Research Commission, and the executive directors of both agencies are directed to assist the task force in meeting its staffing needs.

Section 6. There is hereby appropriated from the general fund the sum of $150,000 to accomplish the study. Any amount remaining following the completion of the study shall revert to the general fund.

APPENDIX C

REQUEST FOR PROPOSALS FOR CONSULTING SERVICES FOR THE SPECIAL TASK FORCE ON ELECTRIC RESTRUCTURING

Overview

Since the Federal Energy Regulatory Commission issued FERC orders, which opened up the transmission system for wholesale competition in the electric utility industry, many states have examined the implications of restructuring their electric utility industry to permit retail competition. The Kentucky General Assembly, through the Special Subcommittee on Energy, has examined the issue since the middle of 1997 by holding workshops, public hearings and receiving testimony from interested parties.

An unsuccessful attempt was made during the 1998 Session of the General Assembly to establish retail competition. House Bill 443 provided for complete market opening by the year 2005. During the same session, the General Assembly passed House Joint Resolution 95, which established the Special Task Force on Electric Restructuring and appropriated $150,000 to fund its activities (Attachment 1). The Task Force on Electric Restructuring consists of 20 members from both the executive and legislative branches and is charged with examining the implications of allowing retail competition in Kentucky. House Joint Resolution 95 also requires that the task force report its findings and recommendations to the Legislative Research Commission and the Governor by November 15, 1999.

One of the principal responsibilities of the Special Task Force on Electricity Restructuring is to produce a study on electric restructuring in Kentucky. In support of that effort, the Legislative Research Commission, on behalf of the Special Task Force on Electric Restructuring, seeks consulting services for a project manager, technical advice, and technical assistance. The project manager will provide the knowledge of proven methodologies, techniques and resource requirements to lead a staff team from the Legislative Research Commission and the Public Service Commission.

Additionally, the consultant will be responsible for working directly with staff in the preparation and review of reports identified in the scope of work, and by attending monthly task force meetings and progress report meetings with the co-chairs. The consultant will also be responsible for the review of the final report and recommendations prepared by LRC and PSC staff before issuance by the task force. The consultant will not be directly responsible for testifying before the task force.

A standard information packet offering general background information on Kentucky's utilities is available by request. Questions concerning this RFP or the standard information

packet should be directed to Tanya Monsanto, Legislative Research Commission, 127 Capitol Annex, Frankfort, KY 40601. Tel: (502) 564-8100. Fax: (502) 564-6543.

Scope of Work

The consultant shall act as project manager for a research team comprised of staff at the legislative research commission (LRC) and the Public Service Commission (PSC) in performing a study required by HJR 95. The contract term is for 6 continuous months with an additional 2 to 4 weeks from August 10, 1999 to November 15, 1999 to review the final report and the recommendations of the task force. The consultant will provide the technical advice, assistance and support to:

1. Quantify the short and long run marginal cost of electricity in Kentucky under retail competition and under the current cost of service regulation. Identify the factors that affect both short and long run marginal cost, as well as, the past and anticipated volatility of any one or all of those factors.

2. Isolate factors that would contribute to a difference in the price of electricity to customers in urban and rural areas under retail competition. Generate an estimate that measures the impact that retail competition will have on the price of retail electricity sales, including generation, to urban and rural customers.

3. Describe Kentucky's current electricity trade with other states and quantify the expected impact of retail competition on Kentucky's export balance of electricity.

4. Identify the items that could potentially be the stranded costs or negative stranded costs under retail competition. Generate an estimate of positive or negative stranded costs in Kentucky.

5. Identify the factors that determine whether a provider of electricity generation can achieve market domination sufficient to distort prices. Examine these factors in the context of Kentucky's market.

6. Generate estimates that would measure the potential impact of retail competition on the future use of coal in Kentucky's fuel mix for generation, and

7. Describe the current industry structure of Kentucky's electric utilities including the growth and change in its unregulated businesses. Identify the mechanisms by which an unregulated business could utilize assets from the regulated side of the utility to gain a competitive advantage over incumbents in the marketplace for energy-related services such as HVAC and energy efficiency.

Timetable for Project

December 3, 1998	RFP issued
January 4, 1999	Proposals due in response to RFP
January 18, 1999	Top three proposals selected/ Oral presentations scheduled
February 8, 1999	Consultant approved by Task Force
February 9, 1999	Personal Service Contract awarded/ Consultant begins work
April 19, 1999	Report due on questions 1 and 2
June 14, 1999	Report due on questions 3 and 4
August 10, 1999	Report due on questions 5, 6, and 7
August 10-November 15	Review and critique final report and task force recommendations

Oversight Responsibility

Oversight responsibility for this contract shall be the Co-chairs of the Task Force on Electric Restructuring. The co-chairs, along with LRC or LRC/PSC staff, shall be responsible for:

1. Monitoring the overall operation of the project.
2. Determining changes in the end product that may be required.
3. Identifying problems and charting the progress of the project.
4. Approving any changes, modifications to the consultant's work plans or methodologies, and
5. Attending monthly progress report meeting with the consultant, and
6. Determining compliance with the terms of the contract.

Project Finance

The consultant shall certify the actual time spent working on the project to the co-chairs by submitting both monthly time sheets and status reports. The consultant shall also present an oral summary of the consultant's monthly progress report to co-chairs and staff.

Unless an acceptable alternate payment schedule can be developed, the following payment schedule shall apply: ordinary expenses shall be paid on a monthly basis. Payment of the contract shall be in three installments that coincide with the timetable for delivering reports on questions identified in the scope of work. Up to twenty-five percent (25%) of the contract fee will be withheld until after the final report of the task force is presented and reviewed by the Legislative Research Commission.

Information Provided by the Bid Offerer

Interested bidders shall submit ten (10) copies of the proposal by January 4, 1999 to:

Tanya Monsanto
Legislative Research Commission
Room 127, Capitol Annex
Frankfort, Kentucky 40601
Phone: (502) 564-8100
Fax: (502) 564-6543

All proposals shall contain the following information:

1. A description of the quantitative techniques, models, software, and methods of analysis that will be utilized in fulfilling the requirements of the question detailed in the scope of work above.

2. A statement that details specific software required to complete each item listed in the scope of work and that identifies any licensing agreements on the software held by the consultant that would prohibit or restrict staff access to or use of that software.

3. A commitment by the consultant to meet deadlines according to the project timetable or a commitment to meet alternate dates by which each item could be completed.

4. A description of the consultant's relevant work in both the public and private sector, experience, and qualifications with specific reference to energy or utility-related modeling and to energy markets in the ECAR region. Provide summaries of relevant work along with a contact name and phone number of the party for whom the work was produced. (References will be contacted.)

5. A description of the experience and qualifications of the contractor's staff or personnel that would be required to complete any of the items in the project.

6. The identification of a not-to-exceed fee and that your firm would charge to complete the scope of the work along with a cost structure statement that includes a break-down of the monthly and hourly rate and estimated reimbursable expenses such as travel, housing, and personnel.

7. A project work plan that identifies both the tasks and the amount of time and personnel from both the LRC and the PSC needed to accomplish each task.

8. A statement of any conflicts of interest which could call into question the objectivity of the consultant or the work product. If the bidder has worked for utility, Attorney General's Office, consumer affairs, or other interest group, such as the Kentucky Industrial Utility Customers, in Kentucky, or for the Kentucky Public Service

Commission, please provide a statement that describes the type of work performed, contact name and telephone number.

Bid Evaluation

All bids shall be evaluated and the top three finalists selected by the scoring committee of the Task Force on Electric Restructuring. The top three bidders may be required to make oral presentations to the full Task Force. Evaluation criteria shall consist of:

1. Quantative techniques, models, and methods proposed fee for completing scope of work.

2. Experience with electric utility analysis, demonstrable understanding of fuel and energy market dynamics in ECAR, national perspective, familiarity with Kentucky's resources and electric industry, and demonstrated ability to determine cost of generation.

3. Qualifications and experience of both the lead and of any additional personnel required to complete the project, and

4. Price for completing the project.

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