BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION
CASE NO. EM-97-515
WESTERN RESOURCES, INC
AND KANSAS CITY POWER AND LIGHT
SUPPLEMENTAL DIRECT TESTIMONY OF
ROBERT M. SPANN

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Issues:	Market Power-Related Issues
Witness:	Robert M. Spann
Sponsoring Parties:	Western Resources, Inc. and Kansas City Power & Light Company
Type of Exhibit:	Supplemental Direct Testimony
Case No.:	EM-97-515

IN THE MATTER OF THE MERGER APPLICATION

OF

WESTERN RESOURCES, INC.

AND

KANSAS CITY POWER & LIGHT COMPANY

SUPPLEMENTAL DIRECT TESTIMONY

OF

ROBERT M. SPANN
WESTERN RESOURCES, INC.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

SUPPLEMENTAL DIRECT TESTIMONY
OF
ROBERT M. SPANN
VICE PRESIDENT
CHARLES RIVER ASSOCIATES INCORPORATED

I. INTRODUCTION AND QUALIFICATIONS

Q. ARE YOU THE SAME ROBERT M. SPANN WHO FILED TESTIMONY ON BEHALF OF APPLICANTS IN THIS DOCKET ON SEPTEMBER 18, 1997?

A. Yes, I am.

Q. DO YOU HAVE ANYTHING TO ADD TO THE DISCUSSION OF YOUR QUALIFICATIONS CONTAINED IN YOUR EARLIER TESTIMONY IN THIS MATTER?

A. Yes, I do. In September of 1997, I filed testimony at the Federal Energy Regulatory Commission ("FERC") on behalf of Western Resources and KCPL in connection with their merger application. That testimony is provided as Schedule RMS-1 to this supplemental testimony. In October 1997, I filed testimony at FERC on behalf of Kentucky Utilities and Louisville Gas and Electric in connection with their merger application. In each of those cases, my testimony analyzed the effects of the proposed merger on competition.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by counsel to Applicants, in response to this Commission's Pre-Hearing Conference Order, dated August 19, 1997 (Order No. 6) and its Order on Reconsideration, dated October 6, 1997 (Order No. 8), to analyze the competitive effects of the proposed merger of Western Resources and KCPL assuming that retail competition has been implemented. As noted just above, I filed testimony at FERC in connection with this proposed transaction. In my FERC testimony, I focused on the effects of the proposed merger on competition in the relevant wholesale markets. In this testimony, I extend my analysis to include retail competition as well.

Q. DOES DIRECT RETAIL COMPETITION EXIST IN THE AREAS IN WHICH THE APPLICANTS OPERATE?

A. No, it does not. Counsel has informed me that utilities have exclusive service areas in Kansas and Missouri. Although there is some limited indirect competition – fringe area competition and industrial location competition – full-retail competition does not exist in Kansas or Missouri today. Implementation of full-scale retail competition would require action by the state legislatures and/or Congress. Thus, the institutional framework and other specific factors affecting any implementation of retail competition in Kansas and/or Missouri have yet to be established.

Q. WHAT DOES THE FACT THAT RETAIL COMPETITION DOES NOT YET EXIST IN KANSAS OR MISSOURI IMPLY FOR YOUR ANALYSIS?

A. Perhaps the most significant implication is that any analysis at this point will have to rely on a number of assumptions, some of which, with hindsight, may prove to be unrealistic. Moreover, once retail competition is introduced, new institutions with competing incentives are likely to emerge. For example, the introduction of retail competition is likely to be accompanied or preceded by the formation of an ISO. Such an entity may well have objectives and abilities that differ from any current entity in the relevant market. This could lead to changes in the way transmission systems are operated. These changes may reduce the frequency with which binding transmission limits are encountered and lead to increases in effective transfer capability between regions and control areas. Similarly, as markets evolve, both suppliers and customers may adapt to competition in ways that are difficult to predict before the fact. The world likely will look very different with retail competition, in ways that are not necessarily apparent at this time. Thus, one should regard any conclusions based on an analysis of existing conditions or speculation about future conditions with a healthy dose of skepticism.

Q. COULD YOU BASE YOUR ANALYSIS ON THE EXPERIENCE OF OTHER JURISDICTIONS?

A. There is not yet sufficient experience with retail competition in other states to make such an analysis feasible. While most states have discussed restructuring in one form or another, in most cases these discussions remain rather preliminary. Indeed, only a very few states are on the verge of implementing full-scale retail choice. Thus, to date very little experience has accumulated in the U.S. Moreover, the states that have made the most progress towards implementation differ in certain important respects that may make it difficult to generalize from their experience to the situation in either Kansas or Missouri. While the experience with retail electric competition is fairly limited in the U.S. to date, a number of states will be implementing competition in the next one to three years. As this happens, substantial information will become available that can aid policymakers and analysts considering retail competition in Kansas and Missouri.

Q. HAVE THE STATES THAT ARE FARTHER ALONG TOWARDS IMPLEMENTATION ADOPTED A SINGLE MODEL OF RETAIL COMPETITION?

A. No, they have not. To the contrary, the details of implementation vary considerably across those states that have articulated policies to date. In some cases, specific restructuring plans differ in significant respects even for individual utilities in the same state.

Q. PLEASE PROVIDE SOME EXAMPLES.

A. Different states have adopted different approaches to issues such as the timing of implementation; the manner in which retail choice will be phased in (e.g., whether all customers will have a choice of suppliers at once or whether some customers will have choice of supplier now and others not until later on); divestiture of generation; and the form of market organization. For example, in California all customers of investor-owned utilities will have retail choice starting in January

1998. In contrast, in Pennsylvania, retail competition will be phased in gradually between 1999 and 2001. (A pilot program began in 1997.) Other states plan to phase in retail choice at different rates. States similarly have taken very different positions with respect to divestiture of generating assets. For example, Maine and New Hampshire have mandated complete divestiture, while Pennsylvania has not required any divestiture. In other states, principally New York and California, divestiture has not been mandated across the board, but utilities have entered into individual settlement agreements requiring substantial divestiture.

The details of implementation may even vary for different utilities within the same state. In New York, for example, full retail access to competitive energy and capacity markets will be available to Orange and Rockland Utilities by May 1, 1999. Retail competition will be phased in more gradually for customers of Rochester Gas and Electric. The first group of Rochester Gas and Electric's customers will gain retail choice in energy markets in July 1998 and all retail customers will gain access to competitive energy and capacity markets by July 2002.

Q. WHAT DO YOU CONCLUDE FROM THE FACT THAT DIFFERENT STATES HAVE ADOPTED DIFFERENT APPROACHES?

A. It appears that the details of restructuring in any specific state will reflect local or regional concerns and market conditions. Moreover, the particular policy outcomes in any jurisdiction no doubt reflect a balancing of the competing objectives and interests before the relevant policymakers in each jurisdiction.

Thus, it is clear that there is no "cookie cutter" approach to implementing retail competition that can be assumed for purposes of this analysis.

It should also be noted that some of the approaches that are adopted ultimately may prove to be more successful than others. Thus, states that are later to adopt retail competition will have the opportunity to learn from the experience of other jurisdictions.

Q. GIVEN THAT RETAIL COMPETITION DOES NOT YET EXIST IN KANSAS OR MISSOURI, HOW DID YOU CONDUCT YOUR ANALYSIS?

A. While retail competition currently does not exist in Kansas or Missouri, wholesale competition does exist throughout the region. Thus, it seems logical to approach the analysis of retail competition by assessing the degree to which one can draw inferences about the merger's potential effects on retail competition from the analysis of wholesale competition.

In my FERC testimony submitted in connection with this proposed merger, I analyzed the effects of the transaction on wholesale competition following the approach outlined in the Department of Justice/Federal Trade Commission *Merger Guidelines* and the general approach in Appendix A to

FERC's *Merger Policy Statement.*[1] My analysis showed that the proposed merger raises no concerns about competition in the relevant wholesale markets.

In this testimony, I turn to the question of whether it would be reasonable to draw inferences about the proposed merger's effects on retail competition from the analysis of wholesale competition.

Q. WHAT DID YOU CONCLUDE ABOUT THE APPLICABILITY OF THE WHOLESALE ANALYSIS TO RETAIL COMPETITION?

A. Introduction of retail competition most likely will involve competition at the electric generation level. The distribution and transmission functions will continue to be regulated. Thus, the antitrust analysis of this merger under the assumption that retail competition exists focuses on competition at the generation level. Competition at the generation level for wholesale sales already exists and is expanding. The conclusions drawn from the analysis of wholesale competition are directly applicable to the retail case. As I explain in detail below, the product and geographic markets relevant for the analysis of wholesale competition are the same relevant markets for analyzing the effects of the proposed merger on retail competition. Thus, in general, the same conclusions hold for both the wholesale and retail markets.

[1] Order 592, *Merger Policy Statement Establishing Factors the Commission Will Consider in Evaluating Whether a Proposed Merger Is Consistent With the Public Interest*, December 18, 1996.

Q. WHY SHOULD THE RESULTS OF THE ANALYSIS OF WHOLESALE COMPETITION BE RELEVANT TO UNDERSTANDING THE EFFECTS OF THE PROPOSED MERGER ON RETAIL COMPETITION?

A. Retail competition will be similar to wholesale competition, but with a much greater number of customers involved. At one level, the introduction of retail competition simply means that retail customers will face the same choices that wholesale customers have today. As I noted in my earlier testimony filed with this Commission, many of the same issues – control of generating capacity and access to transmission and distribution – arise in any consideration of either retail or wholesale competition. If a merger were deemed to have anticompetitive effects on wholesale markets, I would expect that an analysis assuming retail competition would yield similar results. Similarly, if wholesale power markets were highly competitive, or if a merger were found to have no adverse effect on wholesale power markets, I would expect that institutional arrangements could be structured such that a similar degree of competition would exist under full-scale retail competition.

There are several reasons why one would expect the conclusions to be similar for wholesale and retail competition. First, the same capacity is used to generate the electricity sold to both wholesale and retail customers. Thus, the capacity held by competitors that constrains the ability of the merged entity to raise prices in wholesale markets would also constrain the ability of the merged entity to increase prices under retail competition.

Second, it is likely that the entities that currently compete with Applicants in the wholesale market will also compete for retail sales. In particular, the Applicants face competition in wholesale markets from power marketers and from utilities owning generation in surrounding states. In addition to competing directly for retail sales, both power marketers and the generating or marketing divisions of utilities will buy power in the wholesale market for resale, just as they do today. New types of competitors may also emerge under retail competition – just as power marketers have emerged in the wake of FERC Order No. 888 – further intensifying competition.

Q. ARE THERE ANY REASONS WHY THE CONCLUSIONS FROM THE WHOLESALE ANALYSIS MIGHT NOT BE APPLICABLE UNDER RETAIL COMPETITION?

A. My analysis of the relevant wholesale market showed that the merged entity will possess no market power over bulk power. There are two possible reasons why this conclusion might not hold under retail competition. First, in the abstract, it is possible that the introduction of retail competition might lead to changes in physical power flows, such that transmission constraints that were not binding prior to the introduction of retail competition become binding following its introduction, reducing the competitive significance of certain wholesale rivals. However, I show that, in general, if wholesale competition is leading to trading patterns not dramatically different from the trading patterns that would result from economic dispatch, the introduction of retail competition is unlikely to lead to significant changes in physical power flows in the near term. This is true even though retail competition will change the financial transactions between buyers and sellers.[2]

Q. WHAT IS THE SECOND REASON THE CONCLUSIONS OF THIS WHOLESALE ANALYSIS MIGHT NOT APPLY TO RETAIL COMPETITION?

A. There is one issue that arises under retail competition that is usually not an issue under the current regime of regulated retail rates and wholesale competition. This issue revolves around the potential for a generating firm to exploit limitations on transfer capability into its control area in such a way as to limit competitive access to retail customers, thereby allowing it to raise prices above the competitive level. If such strategic unilateral action were possible at all, it would most likely occur within the utility's own control area.

As I explain below, the ability of the firm to exercise such market power will depend largely on the degree to which it operates in a "load pocket." A "load pocket" is an area in which import capability is less than demand in that area. Because of the manner in which electric generation and transmission systems traditionally have been designed and operated, many control areas in the United States are likely to meet this definition of a load pocket. In such circumstances, the utility might be able to exploit the constraint on import capability and increase

[2] As I discuss in more detail later in my testimony, it is important to distinguish between the physical flow of power and the financial transactions between buyers and sellers.

prices in its control area.[3] This exploitation could occur if the firm that owned most of the generation in the control area significantly reduced generation, thereby increasing imports into the region to the point at which imports into the area equaled the transmission limit into the area. Once imports equaled the import limit, the firm could increase prices without having to worry about losing sales to additional imports. Once the import limit was reached, the firm's only additional loss of sales would be from consumers reducing demand as prices increased.

Such strategic exploitation of transmission limits is less likely in cases in which the control area is a net exporter of energy most hours of the year, as are the Applicants. As I explain later in my testimony, a net exporting area can exploit transmission limits only if it is willing to forego profits on all sales outside its control area as well as substantially reducing sales within its own control area.

Since many control areas may be load pockets, this issue will need to be addressed as part of any implementation of retail competition, regardless of whether or not this merger occurs. Finally, as I discuss below, there exist a number of potential ways to mitigate concerns that might arise from load pocket issues.

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[3] I will use the term "control area" to refer to the existing control areas of the Applicants. However, it is possible that with retail competition, an ISO would operate the transmission system in the region as a single control area, and individual utility control areas – as we know them today – would no longer exist.

Q. WHAT DID YOU CONCLUDE ABOUT THE POTENTIAL EFFECTS OF THIS MERGER ON RETAIL COMPETITION?

A. The conclusion that the merger is unlikely to have an adverse effect on competition in wholesale markets applies generally to retail competition as well. Based on current estimates of transmission transfer capabilities, both the Western Resources and KCPL control areas constitute "load pockets" with or without the merger. This means that in implementing retail competition, with or without the merger, the Commission will need to be concerned about the potential exercises of localized market power. Assuming full implementation of retail competition, the level of transfer capability as it exists today is such that there is the potential for localized market power to exist in the Western Resources control area pre-merger and in the combined system control area post-merger. This is less likely to be an issue in the KCPL control area pre-merger. However, a variety of possible mitigation measures could be implemented to alleviate any concerns about the exercise of market power of this type. Given the uncertainties associated with the details of implementation, and the fact that my calculations are based on the transmission system as it is operated today, not as it might be operated by an ISO, it would be premature to implement specific mitigation measures at this time.[4] Moreover, the merger will not preclude the Commission

[4] As I discuss later, my calculations are based on the first contingency transfer limits associated with the transmission system as it exists and is operated today. Mr. Dixon discusses the caveats that should be placed on the results of current load from studies.

from ordering any necessary mitigation measures it would have available absent the merger.

Q. DOES THE LOAD POCKET ISSUE ARISE AS A RESULT OF THIS MERGER?

A. The load pocket issue is not a consequence of the merger, but rather of the introduction of retail competition. In addition, the issue is likely to arise in connection with other utilities under the Commission's jurisdiction when retail competition is implemented. Thus, the Commission will have to address the issue of load pockets with or without this merger.

In this respect, it is important to recognize that there are two analytically distinct sources of change that may arise in connection with evaluating this merger assuming retail competition. First, the merger itself could lead to certain changes in the competitive alternatives available to customers. Second, the introduction of retail competition itself likely will lead to significant change wholly independent of this merger. Indeed, the whole purpose of opening up electric markets to competition is to change the competitive circumstances facing certain classes of customers. This naturally will lead to the evaluation of competitive issues, with or without the merger. Given that the objective of merger analysis is to focus on changes occasioned by the *merger*, it is important to distinguish clearly between issues specifically raised by the merger and issues presented by the introduction of retail competition.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In the next section, I outline the analytical framework used to evaluate the competitive effects of mergers. In Section III, I summarize my analysis of wholesale electricity markets. In Section IV, I turn to the analysis of retail competition.

II. ANALYTICAL FRAMEWORK FOR MERGER ANALYSIS

Q. WHAT FRAMEWORK HAVE YOU USED IN YOUR ANALYSIS OF THE EFFECTS OF THE PROPOSED MERGER ON WHOLESALE COMPETITION?

A. I have followed the framework outlined in FERC's *Merger Policy Statement.* In that document, FERC states that it has adopted the analytical framework outlined in the *Merger Guidelines* used by the Department of Justice and Federal Trade Commission for assessing market power.

Q. WHAT IS THE PURPOSE OF AN ECONOMIC ANALYSIS OF THE COMPETITIVE EFFECTS OF A MERGER?

A. The purpose of the analysis is to determine whether the merger would create or enhance market power and, as a result, have an adverse effect on competition. As with any analysis of antitrust issues, the focus is on the effect on competition, not competitors.

Q. WHAT DO YOU MEAN BY THE TERM "MARKET POWER"?

A. The *Merger Guidelines* defines market power as the ability of a firm profitably to maintain prices above competitive levels for a significant period of time (*Merger Guidelines*, §0.1). I adopt this definition.

Q. HOW IS THIS CONCEPT UTILIZED IN ANALYZING THE EFFECTS OF A MERGER ON COMPETITION?

A. One attempts to determine whether or not the merged firm would be able to increase prices to customers in situations in which neither merging entity, absent the merger, would have such an ability.

Q. DO THE *MERGER GUIDELINES* OR THE *MERGER POLICY STATEMENT* SPECIFY ANY PARTICULAR STEPS FOR ASSESSING WHETHER A MERGER IS LIKELY TO CREATE OR ENHANCE MARKET POWER?

A. Appendix A to FERC's *Merger Policy Statement* identifies several steps to be followed. These steps are patterned after the methodology outlined in the DOJ/FTC *Merger Guidelines*. These steps are: 1) define the relevant product market(s); 2) define the relevant geographic market; 3) analyze concentration in these markets by calculating market shares, the Herfindahl-Hirschman Index (HHI), and the change in the HHI occasioned by the merger and then comparing these results to thresholds set forth in the *Merger Guidelines* and adopted in the *Merger Policy Statement*; and 4) address other considerations and remedial measures if necessary (*Merger Policy Statement*, Appendix A, pp. 1-24). I implemented each of these steps.

Q. HOW DOES ONE DETERMINE THE RELEVANT MARKET FOR THE PURPOSE OF THIS TYPE OF ANALYSIS?

A. The objective is to delineate the product and geographic markets in which the two firms are competitors absent the merger, and to identify competing suppliers that may limit the ability of the merged entity to increase prices.

The first step in defining the market is to identify the products as to which the two merging firms are competitors prior to the merger, and the geographic areas in which they compete. Next, one determines all of the other suppliers that compete for the same business. Competitors include both current competitors and firms that would sell output in competition with the merging parties at prices slightly higher than current market prices.

Q. HOW DO YOU MEASURE MARKET CONCENTRATION?

A. The level of market concentration is measured by computing the HHI. The HHI is the sum of the squared market shares of all of the sellers of the relevant product in the relevant geographic market. The HHI calculation measures the number of sellers and their market shares weighted by their significance in the market.[5] (See *Merger Guidelines*, §1.5.) The higher the HHI, the greater the degree of market concentration. If there were only one seller of the relevant product, the HHI would be 10,000.

Q. ARE THERE GENERALLY ACCEPTED STANDARDS FOR INTERPRETING LEVELS OF MARKET CONCENTRATION AND THE

[5] For example, if there are four sellers of the relevant product, with market shares of 10 percent, 50 percent, 5 percent, and 35 percent, respectively, the HHI is 3,850 (10 squared plus 50 squared plus 5 squared plus 35 squared equals 3,850). In this same example, if there had been four equally sized sellers,

CHANGES IN MARKET CONCENTRATION THAT RESULT FROM A MERGER?

A. Yes, there are. FERC's *Merger Policy Statement* adopts a screening threshold to determine whether the merger could raise significant competitive concerns and require further analysis. This screen analysis is based on the DOJ/FTC *Merger Guidelines*.

> The HHI measures should be compared with the thresholds given in the DOJ *Merger Guidelines*. The Guidelines address three ranges of market concentration: (1) an unconcentrated post-merger market—if the post-merger HHI is below 1000, the merger is unlikely to have adverse competitive effects regardless of the change in HHI; (2) moderately concentrated post-merger market—if the post-merger HHI ranges from 1000 to 1800 and the change in HHI is greater than 100, the merger potentially raises significant competitive concerns; and (3) highly concentrated post-merger market—if the post-merger HHI exceeds 1800 and the change in the HHI exceeds 50, the merger potentially raises significant competitive concerns; if the change in HHI exceeds 100, it is presumed that the merger is likely to create or enhance market power.*
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> * DOJ/FTC *Guidelines*, at 41,558.
> ["Merger Policy Statement," Appendix A, p. 16]

In effect, the *Merger Policy Statement* and the *Merger Guidelines* state that if both of the two merging firms have a small market share for the same products, the merger is unlikely to have an adverse effect on competition. The greater the number of sellers in the market, post-merger, the less likely it is that

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each with a 25 percent market share, the HHI would be 2,500. If there are four sellers with unequal market shares, the HHI will be greater than 2,500.

any given change in the HHI indicates that the merger will have adverse effects on competition.

Q. IF THE CHANGE IN THE HHI EXCEEDS THE LEVELS YOU HAVE DISCUSSED, DOES THIS MEAN THAT THE MERGER WILL HAVE ADVERSE EFFECTS ON COMPETITION?

A. No, not necessarily. The numerical criteria regarding concentration listed above represent a "safe harbor.", Under FERC's *Merger Policy Statement*, the HHI levels are used to determine the point at which no further analysis of the merger is required. If the initial screening analysis indicates that the changes in the HHIs are within these "safe-harbor" levels, no further analysis of the merger is required. If the changes in the HHIs exceed these levels, further analysis may be required, but the merger will not necessarily have an adverse effect on competition.

Similarly, under the DOJ/FTC *Merger Guidelines*, the change in the HHI is used to determine the conditions under which the DOJ/FTC will decide *not* to challenge a merger. The agencies' decision to challenge a merger as one that creates or enhances market power is based on both the numerical criteria listed above and additional analyses of other significant market factors. For example, if a proposed merger results in a post-merger HHI exceeding 1,800 and the change in the HHI exceeds 50 points, the antitrust agencies still may decide not to challenge the merger based on an analysis of other factors. These other factors include the potential for lessening competition through coordinated interactions or through unilateral actions, entry conditions, efficiencies that result from the merger, and the financial strength of the merging firms.

It is also worth noting that only on very rare occasions has the FTC or DOJ challenged a merger when the post-merger HHI is under 1,800 or the change in the HHI is less than 200 points. (See the supplemental testimony of Richard Gilbert on behalf of the Applicants in the FERC proceedings regarding the Baltimore Gas and Electric Company-Potomac Electric Power Company merger, Docket No. EC96-10-000; Malcolm B. Coate, "Economics, the Guidelines and the Evolution of Merger Policy," *The Antitrust Bulletin*, Volume XXXVII, No. 4 (Winter 1992), pp. 997-1024; and Malcolm B. Coate, "Merger Enforcement at the Reagan/Bush FTC," in Malcolm B. Coate and Andrew N. Kleit (editors), *The Economics of the Antitrust Process*, Kluwer Academic Publishers, 1996.)

I discuss the analytical framework for assessing the effects of a merger on competition in greater detail in my FERC testimony. (Please see pp. 19-26 of that testimony.)

III. ANALYSIS OF WHOLESALE COMPETITION

Q. WHAT IS THE RELATIONSHIP BETWEEN THIS DISCUSSION OF THE EFFECTS OF THE PROPOSED MERGER ON WHOLESALE COMPETITION AND THE DISCUSSION PRESENTED IN YOUR FERC TESTIMONY?

A. The principal focus of my FERC testimony was the analysis of the effects of the proposed merger on competition in the relevant wholesale markets. I have been asked by counsel to focus in the current testimony primarily on the effects of the proposed merger on retail competition. However, much of the analysis of retail competition follows directly from the analysis of wholesale competition. My FERC testimony describes each step of the analysis of wholesale competition in detail. To minimize repetition, I have included my FERC testimony concerning this merger as Attachment 1 to this document and I incorporate that testimony by reference. The reader should consult that testimony for details concerning the analysis of wholesale competition. In this section, I summarize the major elements and conclusions of that analysis. For convenience, where appropriate, I have indicated the pages in my FERC testimony to which the reader may turn for a more complete explanation.

Q. WHAT METHODOLOGY DID YOU USE TO ANALYZE THE COMPETITIVE EFFECTS OF THE PROPOSED MERGER ON WHOLESALE COMPETITION?

A. I analyzed the effects of the proposed merger on wholesale competition using the approach outlined in FERC's *Merger Policy Statement* and in the DOJ/FTC *Merger Guidelines.*

Q. WHAT DID YOU CONCLUDE FROM YOUR ANALYSIS?

A. I conclude that the proposed merger of Western Resources and KCPL does not raise any competitive concerns with respect to wholesale electricity markets. I have analyzed concentration for a number of different measures of capacity. The picture that emerges from this analysis is that the combined entity will have a small share of capacity in a broad, active, regional market.

Q. HAVE YOU PERFORMED ANY ANALYSIS OF VERTICAL MARKET POWER ISSUES IN WHOLESALE ELECTRICITY MARKETS?

A. No, I have not. Mergers can present issues involving either horizontal or vertical market power. Horizontal issues involve the exercise of market power at the same stage of production. For example, excessive concentration of ownership of generation might lead to concerns about horizontal market power in generation. Vertical issues involve market power that can be exercised via control over different stages of production. A vertical issue could arise if a merger led to a change in the degree of vertical integration so that the merged entity could exercise market power over different stages of production in such a way that the merging entities could not individually. For example, the merger of a company that only owned generation and a distribution company might present vertical issues. In this case, I have restricted my attention to potential horizontal market power in generation. This is appropriate because the proposed merger will not change the degree of vertical integration in the market and, hence, does not give rise to vertical issues.

There are, however, vertical issues associated with the implementation of retail competition. These generally arise because of the concern that an integrated utility may be able to use control over transmission and distribution lines to exercise market power in generation. As a result of these concerns, the jurisdictions farthest along towards implementation generally have required some form of separation of ownership or control of generation, distribution, and transmission. It is important to bear in mind that these vertical issues would arise when retail competition is implemented regardless of the merger and do not result from the merger.

Q. WHAT IS THE RELEVANT PRODUCT MARKET FOR PURPOSES OF ANALYZING THE EFFECTS OF THE MERGER ON WHOLESALE POWER MARKETS?

A. The relevant product is bulk power. This includes both non-firm and short-term firm wholesale power. (See pp. 7-8, 35-36 of my FERC testimony for a more complete discussion of the relevant product market.)

Q. WHAT IS THE RELEVANT GEOGRAPHIC MARKET FOR PURPOSES OF ANALYZING THE EFFECTS OF THIS MERGER ON WHOLESALE COMPETITION?

A. As I explain in detail in my FERC testimony (pp. 8-10, 38-41, and Appendix 1), the relevant geographic market should be defined to include the capacity that would constrain the ability of the merged firm to raise prices above the competitive level. This would be the capacity that might supply additional output if the merged entity attempted to reduce output and increase prices. Thus, defining the relevant geographic market entails identifying the customers that might be affected by the merger and the suppliers that compete with the merging parties to serve those customers. The merging parties sell wholesale power to customers in the SPP and also to Union Electric, Entergy, St. Joseph Light and Power, and Associated Electric Cooperative (AEC).[6] At this time I filed my FERC testimony, Entergy, St. Joseph Light and Power, and AEC were part of SPP. Since then, those three have left the SPP, but they remain competitors in the relevant geographic market.

Schedule RMS-2 shows the service areas of those utilities that purchase power from the Applicants. The second page of that schedule shows the service areas of the utilities that sold power to customers of the Applicants. The relevant geographic market is depicted in Schedule RMS-3. At a minimum, for purposes of analyzing this merger, the suppliers in the relevant market must include all of the other entities that own generating capacity in the SPP, Entergy, St. Joseph Light and Power, and Associated Electric. In addition, Union can substitute its own generation for purchases from the merging parties. Union also sells power to other customers of the merging parties. Capacity owned by Union constrains the ability of the merging firms to raise prices and, thus, is part of the relevant market. Utilities in MAPP own low-cost coal capacity and sell power to customers of the merging parties in the SPP. Capacity owned by utilities in MAPP competes with the merging parties and is also part of the relevant market, subject to transmission availability between MAPP and the SPP. TVA sells significant amounts of power

[6] Entergy and AEC have announced plans to join SERC. St. Joseph Light & Power has announced plans to join MAPP.

to two major customers of the merging parties, and its capacity constrains prices in the relevant market. The Southern Company is directly interconnected with Entergy a major purchaser from the Applicants. I have analyzed concentration both with and without capacity from TVA and Southern. Whether one includes or excludes TVA and/or Southern, the proposed merger poses no threat to wholesale competition.

Q. HOW DID YOU DETERMINE THAT THIS WAS THE RELEVANT GEOGRAPHIC MARKET?

A. As I explain in detail in my FERC testimony, I determined that this was the relevant geographic market by examining transactions data and actual power flows. (Please see pp. 8-14, 36-54 of my FERC testimony for a more detailed explanation.)

Q. IS IT NECESSARY FOR CAPACITY TO BE PHYSICALLY DELIVERED IN MISSOURI TO PREVENT THE MERGED ENTITY FROM RAISING PRICES?

A. No, it is not. All capacity whose output might increase in response to a price increase by the merged entity limits the merged entity's ability to increase prices. At any given moment, Western Resources generally will be selling power to buyers in numerous locations. Some of these buyers may be located in Missouri and using the electricity they purchase from Western Resources in Missouri. Other buyers located out of state or in other control areas are purchasing power from Western Resources and using that power elsewhere. When Western

Resources increases prices in Missouri, buyers in other control areas using power purchased from Western Resources will substitute purchases from capacity located near them. This can render the price increase unprofitable even if output from that capacity could not be physically or economically delivered to Missouri. Appendix 1 to my FERC testimony contains a more detailed discussion of why examining only physical deliveries to a control area will produce incorrect results when examining electric utility market power issues.

Q. HOW DID YOU MEASURE CONCENTRATION?

A. Following the *Merger Guidelines* and the *Merger Policy Statement*, I measured concentration by calculating the HHI and change in HHI for a number of different measures of capacity in the relevant geographic market.

Q. WHAT MEASURES OF CAPACITY DID YOU ANALYZE?

A. I calculated HHIs for a number of different types of capacity in the relevant geographic market. I analyzed total capacity; two specific components of total capacity – baseload coal and nuclear capacity and peaking capacity; uncommitted capacity; economic capacity; and marginal economic capacity. Each of these measures is discussed in detail in my FERC testimony (pp.14-18; 55-96).

Q. PLEASE BRIEFLY DESCRIBE YOUR ANALYSIS OF TOTAL CAPACITY.

A. Total capacity measures the competitive significance of each of the suppliers in the relevant market. Depicting concentration in the ownership of total capacity is the most straightforward way of presenting market-share data for purposes of a competitive analysis.

Schedule RMS-4 displays the HHI calculation for total capacity.

The post-merger HHI for total capacity in the relevant market is 1,399. The level of this post-merger HHI combined with a change in the HHI of 57 is well within the safe-harbor provisions of FERC's *Merger Policy Statement* and the DOJ/FTC *Merger Guidelines*. This means that the merger is unlikely to adversely affect competition, and no further analysis is required. (See pp. 55-58 of my FERC testimony.)

Q. WHY DID YOU ANALYZE CONCENTRATION FOR BASELOAD AND PEAKING CAPACITY?

A. Coal-fired and nuclear plants account for over 50 percent of the capacity in the regional market I have defined, excluding TVA and Southern. The vast majority of the remaining capacity is gas-fired. A substantial amount of wholesale power market activity in the SPP involves utilities that own baseload coal or nuclear capacity selling power to other entities that have significant amounts of gas-fired capacity when coal-fired capacity is available to displace generation from higher-cost, gas-fired capacity. During off-peak periods and during lower load hours of peak periods, coal-fired capacity can be the marginal generation source in the SPP, and so it is coal-fired capacity that determines prices during those time periods. As a result, one possible concern might be that if the merger substantially increased the concentration of ownership of such capacity, it might lead to price increases. These price increases would be most likely to occur, if they occurred at all, during off-peak hours or under lighter load conditions.

At the other extreme, a concern might arise if the merger were to substantially increase the concentration of ownership of peaking capacity, such that the merged entity could increase prices during peak periods.

Q. WHAT DID YOUR ANALYSIS OF BASELOAD AND PEAKING CAPACITY SHOW?

A. My analysis shows that the proposed merger raises no competitive concerns for either baseload or peaking capacity. The HHI calculations for coal and nuclear capacity are shown in Schedule RMS-5. The change in the HHI for coal and nuclear capacity is 122. The post-merger HHI is 1,210, near the low end of the moderately concentrated range. Taken together, the post-merger HHI and the change in HHI for baseload capacity show that the merger raises no competitive concerns for these capacity measures. (See pp. 58-60 of my FERC testimony.) Control of peaking capacity is not an issue in this merger. KCPL does not have any economic peaking capacity, and so the change in the HHI based on peaking capacity due to this merger is zero. (See pp. 60-61 of my FERC testimony.)

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF UNCOMMITTED CAPACITY.

A. Uncommitted capacity is defined as a utility's total capacity less its peak demand and required reserves. In prior merger and market-power cases, FERC has used uncommitted capacity as a measure of the ability of firms to sell power on a year-round basis. Western Resources has roughly 308 MW of uncommitted capacity; KCPL, however, has no uncommitted capacity. Thus, this merger results in no change in the HHI for uncommitted capacity. (See pp. 61-62 of my FERC testimony.)

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF ECONOMIC CAPACITY.

A. Economic capacity is the total amount of capacity owned by suppliers to the relevant market from which output can be delivered to a market point at a cost less than or equal to a given market price. FERC has stated that economic capacity "is the most important measure because it determines which suppliers may be included in the geographic market" (*Merger Policy Statement*, Appendix A, p. 10).

The *Merger Policy Statement* notes that, because buyers cannot store electricity, products may be differentiated by time. As a consequence, peak and off-peak energy may be distinct products (*Merger Policy Statement*, Appendix A, p. 4). I have taken this into account by measuring economic capacity at different market price levels chosen to reflect different load and market demand conditions. Low prices represent off-peak conditions; high prices represent peaking conditions.

In order to measure economic capacity, it is necessary to calculate the delivered price of energy from each potential supplier. The delivered price is equal to the energy cost plus transmission charges, taking into account line losses.

I calculated the marginal operating cost of each generating unit in the SPP and in Union's control area as well as the generating units that might supply power into the SPP or Union in competition with the Applicants. For each entity in the SPP, I added that entity's ceiling transmission rate to its border. I also included losses when I calculated ceiling transmission rates. For entities outside the SPP/Union area, I added transmission charges to the nearest SPP utility. This calculation results in each unit's delivered costs to the SPP/Union area. The market shares and measures of market concentration for the regional market were computed at different delivered price levels.

An alternative calculation, which I have also performed, would be to recognize that Entergy is becoming a regional hub. Power usually flows from north to south within the SPP. Economic activity at regional market hubs strongly influences prices throughout the region. Thus, market concentration should be calculated on the basis of economic capacity delivered to a market hub or, in this case, Entergy. I have calculated economic capacity based on delivered costs to the Entergy border.

Finally, I show HHI calculations in which I do not add transmission charges to the fuel costs of capacity within the SPP area, but do add transmission charges to the fuel cost of capacity outside of the SPP. This calculation was done to reflect the concept that capacity outside the SPP area incurs an additional wheeling charge (relative to capacity within the SPP area) in order to reach buyers within the SPP/Union area.

To test the sensitivity of the results, I calculated HHIs based on economic capacity at delivered costs to the regional market under three scenarios: 1) including TVA in the relevant market, but excluding Southern; 2) excluding both TVA and Southern; and 3) including both TVA and Southern. I also calculated HHIs and the change in the HHI based on economic capacity delivered to the Entergy border, or regional market hub, for the same three scenarios. I calculated the post-merger HHI and the change in the HHI due to the merger for different price levels chosen to reflect different load and demand conditions. The results of the HHI calculations for economic capacity are shown in Schedule RMS-6.

Regardless of which assumption is made concerning the inclusion of capacity from Southern and/or TVA, the HHI calculations based on economic capacity are generally within the safe-harbor provisions of the *Merger Policy Statement* and the *Merger Guidelines*. The post-merger HHIs are almost always less than 1,800 – unconcentrated or only moderately concentrated. The small number of instances in which the change in the HHI exceeds 100 points generally occurs only when I exclude all of TVA's and Southern's capacity. Given the magnitude of the sales of TVA and Southern in the region, exclusion of all of their capacity clearly overstates any impact of this merger. These results indicate that the merger, overall, should be viewed as within the safe-harbor levels and no further analysis is required. (See pp. 63-84 of my FERC testimony.)

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF MARGINAL ECONOMIC CAPACITY.

A. Marginal economic capacity is the additional amount of capacity that could be delivered to the market for a given increase in price. It measures capacity with costs at or near the general range of market prices, and also measures the capacity that might respond to price increases. This concept is explained in greater detail at pp. 84-93 of my FERC testimony.

I analyzed marginal economic capacity for several different price ranges. For each range, marginal economic capacity was calculated at the capacity that would be economic at the higher range minus the capacity that would be economic at the lower price. The economic capacity used in the calculations was derived using the methodology described just above. I also used the same three cases used in the analysis of economic capacity regarding the inclusion/exclusion of capacity from Southern and TVA. The results of the HHI calculations for marginal economic capacity are shown in Schedule RMS-7.

Under any of the sets of assumptions, the results of the analysis of marginal economic capacity are consistent with the other capacity measures I examined. The HHIs and changes in HHIs taken together indicate that the merger will have no adverse effects on competition. Again, the conclusion is that this merger raises no competitive concerns and no further analysis is required. (See pp. 94-96 of my FERC testimony.)

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSIS OF CONCENTRATION.

A. The analysis of concentration shows that the proposed merger raises no threat to wholesale competition.

IV. <u>ANALYSIS OF RETAIL COMPETITION</u>

A. *OVERVIEW*

Q. PLEASE OUTLINE THE ASSUMPTIONS YOU MADE ABOUT THE INSTITUTIONAL FRAMEWORK ASSOCIATED WITH RETAIL COMPETITION.

A. Given that retail competition currently does not exist in either Kansas or Missouri, it was necessary to make a number of assumptions about the institutional arrangements and other changes that may be introduced along with retail competition. The first assumption I have made is that retail competition will be introduced region-wide. Second, my analysis assumes full implementation of retail competition and deregulation of electric generators.

Q. WHAT ASSUMPTIONS HAVE YOU MADE ABOUT TRANSMISSION AND DISTRIBUTION?

A. I have assumed that both transmission and distribution will remain regulated for the foreseeable future. I have also assumed that the introduction of retail competition will be preceded or accompanied by the formation of an ISO covering the SPP and possibly MAPP. It is my understanding that the Applicants support the creation of a regional ISO. This is discussed in detail in the testimony of Mr. Dixon.

Q. HAVE YOU MADE ANY ASSUMPTIONS ABOUT TRANSMISSION PRICING?

A. I have not made any assumption about the particular form that transmission prices will take. They may be postage stamp rates, distance-based, or location-based. The only assumption I have made with respect to transmission prices is that prices for transactions that cross multiple control areas will be no higher than they are today.[7] This seems reasonable in light of recent movement towards open access, more competitive wholesale markets, and pressures for regional transmission pricing.

Q. HAVE YOU RULED OUT ANY PARTICULAR ORGANIZATIONAL FORMS IN CONDUCTING YOUR ANALYSIS?

A. No, I have not. The only assumption I have made in this regard is that the implementation of retail competition will not preclude efficient forms of market organization. For example, restructuring could be accompanied by the creation of a PoolCo, competing PoolCos, or even an OPCo model.[8] The particular form of

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[7] This excludes possible congestion charges that could be imposed to ration capacity if otherwise economic flows were being prevented due to a lack of transmission availability.

[8] "POOLCO" and "OPCO" refer to different forms of market organizations that have been discussed in connection with restructuring. The "POOLCO" concept involves a separate operator (and perhaps owner) of the regional transmission system. All generators submit price and quantity bids for supplying electricity to the grid. The pool operator then determines how much generation is necessary to meet

organization need not be specified at this point in order to assess the effects of the merger on retail competition.

Q. ARE YOU RECOMMENDING THAT THE COMMISSION ADOPT ANY OF YOUR ASSUMPTIONS AS POLICY IN IMPLEMENTING RETAIL COMPETITION?

A. No, I am not. It is my opinion that it is neither possible nor desirable to specify every element of retail competition in this merger proceeding. Before retail competition is introduced, the regulatory commissions and legislatures will have to address the fundamental, generic policy issues associated with implementing retail choice. It is likely that those policy issues will be the subject of proceedings devoted specifically to those questions. In addition, it is my understanding that retail competition will not be implemented for at least three to five years in Kansas or Missouri. Given that time frame, the Commissions will be able to observe and benefit from the experience of other jurisdictions that are

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demand and sets a price for each hour. That price is paid to all generators who generate and is the price charged (after adjustment for transmission cost, losses, and some other factors) to all purchasers. In this model, all transactions go through the pool, and there are no direct transactions (other than financial hedging instruments) between generators and ultimate customers. This is generally the type of system that was implemented in the United Kingdom when the government-owned electric system was privatized and competition introduced.

An alternative way of organizing competitive electric generation markets has been referred to as "OPCO." The "OPCO" concept involves a transmission system operator and bilateral sales contracts between electric generating companies and customers. Generating companies sell power to customers (rather than through a pool) and arrange for transmission service from the operator of the transmission system. Generally, when other states have considered adopting retail competition, the issue of whether to have a "POOLCO" type of market or an "OPCO" market or some combination thereof has assumed great importance.

implementing retail choice in the more immediate future. Therefore, I have tried to base my analysis on assumptions that are as generic as possible, but that still seem plausible.

Q. WILL THIS MERGER FORECLOSE THE COMMISSION FROM IMPLEMENTING ANY SPECIFIC POLICIES THAT IT MIGHT CHOOSE TO ADOPT ABSENT THE MERGER?

A. Not to the best of my knowledge. Merger analysis traditionally focuses on what factors change as a result of the particular merger under consideration. On the basis of the information available to me to date, I see no reason why the merger of Western Resources and KCPL would foreclose any policy options the Commission might exercise in the future absent the merger. For example, I assume that in Missouri, as in other jurisdictions, the Commission will have the option to address concerns about the market power of individual firms at the time it implements retail competition. This type of investigation is likely to occur as retail competition policies are formulated, with or without this merger. For example, both California and New York have addressed market power concerns involving specific utilities in connection with their restructuring efforts. I see no reason why the Missouri Commission would be prevented from addressing any market power concerns it might have once the framework for implementing retail competition has been established more firmly. By that time, the Commission will have information both on the behavior of the merged entity and on the results of retail competition implementation in other jurisdictions.

B. *APPLICABILITY OF THE WHOLESALE ANALYSIS TO RETAIL COMPETITION*

Q. DO THESE RESULTS OF THE WHOLESALE ANALYSIS SHED ANY LIGHT ON THE LIKELY EFFECTS OF THE MERGER ON RETAIL COMPETITION?

A. The results of the wholesale analysis are directly applicable to the analysis of retail competition as well. The proposed merger raises no concerns with respect to retail competition in the relevant regional market.

As I indicated earlier in my testimony, retail competition involves giving retail customers the same options as existing wholesale customers. The same generating capacity which constrains the merged firm's ability to increase prices to wholesale customers also constrains the merged firm's ability to increase prices to retail customers.

Although it is difficult to predict the exact nature of retail competition, some generalizations are possible. Many larger industrial and commercial customers are as large or larger than some existing municipal and cooperative wholesale customers. With full implementation of retail competition, smaller commercial and residential customers will probably purchase power from power marketers (who may or may note be affiliated with generating companies). Such power marketers will aggregate the requirements of numerous small customers and buy or broker power in bulk, much as they do today.

This means that it is the control and ownership of the same generating capacity in the same region that is relevant for analyzing both wholesale and retail competition in electric generation. Thus, one looks at the same relevant product and geographic market(s) to analyze either wholesale or retail competition at the generation level.

Q. DO POWER MARKETERS PLAY A SIGNIFICANT COMPETITIVE ROLE TODAY?

A. Power marketers have emerged as a major competitive influence in the wake of open transmission access. Schedule RMS-8 shows the growth of sales by power marketers in MWH between 1995 and third-quarter 1997. In the first quarter of 1995, sales by power marketers totaled 2.7 MWH. In the first quarter of 1996, just prior to the issuance of FERC Order No. 888 requiring utilities to file open access transmission tariffs, sales by power marketers totaled 27.2 million MWH. By the third quarter of 1997, power marketer sales reached 451.6 million MWH.

Q. DO THE APPLICANTS MAKE SIGNIFICANT SALES TO POWER MARKETERS?

A. Yes, they do. Schedule RMS-9 shows short-term firm and non-firm wholesale sales by Western Resources and KCPL to utilities and power marketers in 1995 and 1996. As that schedule shows, in 1996, approximately 22 percent of Western Resources' sales and 10 percent of KCPL's sales were to power marketers. These percentages reflect sales in dollars; they would be even higher based on MWH.

It is also especially important to note the dramatic increase in sales by the Applicants to power marketers between 1995 and 1996. As Schedule RMS-9 shows, Western Resources' total short-term firm and non-firm sales, measured in MWH, grew by over 50 percent between 1995 and 1996. Over the same period, sales to power marketers increased by over 3500 percent, while sales to utilities increased by 10.5 percent. KCPL's total short-term firm and non-firm sales were essentially flat between 1995 and 1996. Sales to power marketers increased by 150 percent, while sales to utilities declined by approximately 6 percent.

The increasing importance of the Applicants' sales to power marketers is also reflected in Schedule RMS-10. Schedule RMS-10 lists the top 10 non-firm and short-term firm wholesale customers for Western Resources and KCPL in 1995 and 1996. The schedule indicates a significant shift in the nature of wholesale transactions during that period. In 1995, none of Western Resources' top 10 customers were power marketers; in 1996, three power marketers were among Western Resources' top 10 customers. In 1995, only one of KCPL's top 10 customers was a power marketer. In 1996, two power marketers were among KCPL's top 10 customers and their purchases had increased substantially. Moreover, Entergy, a Tier 2 entity to KCPL and a major participant in the regional market, joined the list of KCPL's top 10 customers in 1996.

Q. WHY ARE THESE CHANGES BETWEEN 1995 AND 1996 IMPORTANT TO YOUR ANALYSIS?

A. These changes are important for three reasons. First, these changes show how much and how quickly markets can change as a result of the introduction of competition. Early in 1995, prior to FERC's open transmission access notice of Proposed Rulemaking, power marketers were virtually non-existent. Now power marketers are a major force in electric power markets. It is quite possible that the introduction of retail competition similarly lead to major changes that will outweigh any effect that this merger on power markets.

Second, they show the general broadening of markets and trading that have occurred in response to widespread open access transmission. Third, these changes provide further evidence that the relevant market is a broad region, not narrow geographic areas such as individual utility service areas.

The substantial number of transactions with power marketers reduces the likelihood that individual customers or narrow geographic areas can be targeted for price increases. If the merged entity attempted to increase prices to some customers but not to others, power marketers could simply resell power they are already purchasing to the customers whose prices were increased. The ability of large traders to take advantage of such arbitrage possibilities reduces the likelihood of price discrimination and means that relevant markets are broad, not narrow. Targeting individual customers for price increases is possible only when sellers can prevent buyers whose prices are not increased from reselling output to customers whose prices are increased. Western Resources and KCPL make significant sales to power marketers whose primary business is buying and reselling electricity. When Western Resources or KCPL sells to a power marketer, they generally do not know the identity of the ultimate purchaser. This reduces the likelihood of targeted price increases to individual utility customers.

Q. DO POWER MARKETERS MAKE SIGNIFICANT SALES IN THE RELEVANT GEOGRAPHIC MARKET?

A. Yes, they do. In 1996, power marketers sold 11.1 million MWH in the SPP. Of this amount, 6.8 million MWH were sales to utilities and 4.3 million MWH were sales to other power marketers (see *Power Markets Week*, April 21, 1997, pp. 1,7). To put this amount in perspective, the combined non-firm and short-term firm sales by KCPL and Western Resources totaled 7.5 million MWH in 1996. In the aggregate, KCPL and Western Resources sold 1.5 million MWH to power marketers and 6.0 million MWH to other utilities (including each other). Aggregate sales of non-firm and short-term firm power by both merging parties to utilities were less than aggregate sales by power marketers to utilities in the SPP. If I eliminate sales to Union (which is in MAIN), the combined Western Resources and KCPL's 1996 sales of non-firm and short-term firm power to utilities in the SPP totaled 4.7 million MWH – or about 30 percent less than sales by power marketers to utilities in the SPP.

All customers of Western Resources and KCPL that identify specific suppliers on FERC Form 1 made some purchases from power marketers in 1996. I also have examined sales by power marketers to other customers of Western Resources. Reports filed by power marketers at FERC indicate some sales by power marketers to smaller entities such as the Kansas City Board of Public Utilities, Kansas Municipal Energy Agency, and Midwest Energy.

Q. IS THERE ANY REASON WHY THE GEOGRAPHIC MARKET RELEVANT TO THE ANALYSIS OF RETAIL COMPETITION MIGHT BE NARROWER THAN THE GEOGRAPHIC MARKET RELEVANT TO THE ANALYSIS OF WHOLESALE COMPETITION?

A. Yes, in theory, there is. The availability of transmission is any important factor in determining the scope of the relevant market. Thus, it is necessary to determine whether the introduction of retail competition is likely to change the availability of transmission in any significant way. In theory, if retail competition led to significant changes in physical power flows, transmission constraints that were not binding previously might become binding under retail competition. The potential effect of this could be to diminish the competitive significance of certain entities relative to their significance under wholesale competition alone.

Q. WHY ARE YOU EMPHASIZING THE ROLE OF "PHYSICAL POWER FLOWS" IN THIS CONTEXT?

A. I am emphasizing physical power flows because it is important to distinguish clearly among transactions and financial flows versus the actual physical flows of power. Transactions and financial flows are likely to change significantly with the introduction of retail competition, as customers shift to new providers. However, financial flows can change significantly with little or no change in the underlying physical flows of power. This distinction is important because it is physical, not financial, flows that determine the availability of transmission capacity.

This point can be illustrated with a simple example. There are two interconnected utilities, A and B; each has an exclusive franchise for retail sales. Assume Utility A has more lower-cost generation than Utility B and, prior to implementation of retail competition, is selling 150 MW to Utility B. For simplicity, assume that utilities A and B each have native loads of 1,000 MW.

Assume that retail competition is introduced simultaneously in both service areas. Further assume that, initially, Utility A aggressively markets power to Utility B's former customers and secures 400 MW of business from retail customers in Utility B's control area. This means that Utility B has now lost 400 MW of business. Instead of having 1,000 MW of native load, Utility B has 600 MW of sales in its control area. Utility B ceases to purchase 150 MW at wholesale from Utility A and also has 250 MW of idle generating capacity that was previously supplying native load in its control area. Utility B then attempts to market this idle capacity by selling to retail customers in Utility A's service area. Assume Utility B is partially successful in this effort and obtains 200 MW of business from retail customers in Utility A's control area.

The financial and physical flows are calculated as follows. Utility A has 400 MW of sales in Utility B's control area and 800 MW of sales in its own control area.[9] Utility B has 200 MW of sales in Utility A's control area and 600 MW of sales in its control area. These are the financial transactions and clearly represent a significant change from the transactions that were occurring prior to the introduction of retail competition.

The physical flows of power in this example do not change significantly when retail competition is introduced. Prior to the introduction of retail competition, the physical flow of power was 150 MW from Utility A to Utility B. With retail competition, Utility A sells 400 MW in Utility B's control area and Utility B sells 200 MW in Utility A's control area. The physical flow of power is the net effect of these transactions, or a physical flow of 200 MW from Utility A to Utility B.

This same result can be obtained from a comparison of load and generation in the two control areas. Prior to the introduction of retail competition, Utility A's plants produced 1,150 MW – the 1,000 MW native load in Utility A's control area plus the 150 MW sold at wholesale to Utility B. Plants in Utility B's control area produced 850 MW – the 1,000 MW native load in Utility B's control area less the 150 MW Utility B purchased at wholesale from Utility A.

After the introduction of retail competition, Utility A's plants produce 1,200 MW – the 800 MW Utility A sells in its control area plus the 400 MW it

[9] Utility A had 1,000 MW of native load in its control area prior to the introduction of retail competition. The 800 MW is the 1,000 MW control area load less the 200 MW sold by Utility B in Utility A's control area.

sells in Utility B's control area. Utility B's plants produce 800 MW – the 600 MW Utility B sells in its control area plus the 200 MW it sells in Utility A's control area. Thus, the short-term effect of introducing retail competition is a 50 MW increase in the output of Utility A's generators and a 50 MW reduction in the output of Utility B's generators.

Q. HOW DO YOU INCORPORATE TRANSMISSION LIMITS IN YOUR EXAMPLES OF THE AMOUNT OF POWER ONE UTILITY COULD SELL IN ANOTHER UTILITY'S CONTROL AREA?

A. It is important to recognize that electric transmission lines are not the same thing as railroad cars or trucking lines or other shipping mechanisms. If the transfer capacity is 100 MW from Utility A to Utility B and if the transfer capacity is 100 MW from Utility B to Utility A, this does not mean that generators located in Utility A's control area can only sell 100 MW to customers located in Utility B's control area or, conversely, that generators located in Utility B's control area can only sell 100 MW in Utility A's control area. What the transmission limit means is that the *net* flow of physical power between the two control areas cannot exceed 100 MW.[10]

For example, if Utility A, or generators located in Utility A's control area, are selling 300 MW to customers located in Utility B's control area and

[10] As noted earlier, I am assuming that an ISO would operate the transmission system under full implementation of retail competition. The ISO would collect all schedules for power transactions and determine both net flows and whether those net flows violated any transmission limits. I am also assuming that the ISO would counter-schedule transactions.

generators in Utility B's control area are selling 350 MW to customers located in Utility A's control area, the two flows almost cancel out and there is only a net flow in a physical sense of 50 MW from B to A. Thus, in this example, even though there was only 100 MW of transmission capacity from Utility A to Utility B and vice versa, generators in Utility A's control area could sell 300 MW to generators in Utility B's control area, while generators in Utility B's control area could sell 350 MW to customers in Utility A's control area. The actual flow over the line that determines whether a transmission limit will be reached is the absolute value of the difference between sales from A to B and sales from B to A.

Q. HOW LIKELY IS IT THAT THE INTRODUCTION OF RETAIL COMPETITION BY ITSELF WILL LEAD TO LARGE CHANGES IN PHYSICAL POWER FLOWS SUCH THAT TRANSMISSION CONSTRAINTS THAT ARE NOT NOW BINDING BECOME BINDING?

A. The near-term effect of retail competition is not likely to change physical power flows substantially.

Q. PLEASE EXPLAIN FURTHER WHY PHYSICAL FLOWS ARE UNLIKELY TO CHANGE SUBSTANTIALLY AS A RESULT OF IMPLEMENTING RETAIL COMPETITION.

A. If wholesale markets are functioning competitively, and if individual utilities are using wholesale trading to minimize power supply costs, then physical flows are unlikely to change significantly in the near term as a result of introducing retail competition. If each individual control area dispatches generation to minimize operating costs (i.e., economic dispatch) and always buys from others when outside purchases are priced lower than the control area's marginal generating costs, then trading among utilities and the participation of power marketers and other resellers generally will lead to an efficient, least-cost dispatch of generation within the market used for analyzing wholesale competition, subject to transmission charges.

The introduction of retail competition should result in a least-cost or economic dispatch (subject to transmission prices and constraints) of all of the plants in a given region. Whenever Plant A can produce power at a cost lower than Plant B, Plant A will be more likely to obtain sales than Plant B. This is no different from the situation that exists today in which Utility B would buy power from Utility A whenever Utility A's marginal costs (plus transmission to B) were less than Utility B's marginal costs.

It is possible that wholesale markets are not yet operating with perfect efficiency and trading among utilities is not precisely equal to economic dispatch, given the level of transmission charges. In this case introduction of retail competition may improve the efficiency in markets and produce results closer to true economic dispatch given the level of transmission costs. This would result in increased exports from low cost areas to high cost areas.

In hours when a control area is an exporter now, its exports will probably increase. In hours when a control area is an importer now, its imports will probably increase. As I discuss below, the Applicants' control areas tend to be net exporters of power, except possibly at the time of summer peaks. This means that if retail competition changes power flows on the applicants' control areas it is likely to increase exports during most hours of the year.

Finally, the analysis just described may hold only in the short to intermediate run. In the longer run, as entry occurs and capacity is added, net flows of real power may change if retail competition leads to different types of generators being constructed in different locations than one would have observed under regulation. However, when one is considering a long enough time period for entry to occur, one is less concerned with market power issues because entry will resolve many of those issues. Hence, the market power analysis properly focuses on the short run.

Q. ARE THERE OTHER FACTORS THAT COULD CHANGE PHYSICAL POWER FLOWS?

A. Yes, there are. Regardless of whether or not retail competition is introduced, power flows between control areas will be determined both by marginal generating costs in different control areas and marginal transmission costs. Whenever marginal generating costs in control area A plus marginal transmission charges from control area A to control area B are less than marginal generating costs in control area B, there will be net flows of power from control area A to control area B. This means that changes in transmission prices, as well as changes in fuel prices, can and will affect physical power flows.

Reductions in transmission rates will tend to increase exports of power from low generating cost areas to higher generating cost areas. Lower transmission rates will increase exports from control areas that are already net exporters of power and increase imports into control areas that are net importers of power.

The Applicants have informed me that the SPP is planning to file a regional transmission tariff that will result in transmission prices for most transactions that are lower than current transmission prices. I would also expect that any introduction of retail competition would be accompanied by an ISO and other institutional arrangements that will result in lower effective transmission rates than those that exist today. The ultimate effect will be to increase exports from low-cost regions and, unless transmission limits not now binding become binding, broaden markets.

The SPP regional transmission tariff is likely to be implemented well before retail competition is implemented. One will be able to observe the effects of lower transmission rates on physical power flows well before the implementation of retail competition.

Q. ON BALANCE, WHAT ARE THE IMPLICATIONS OF THESE CONSIDERATIONS FOR THE RELEVANT PRODUCT AND

GEOGRAPHIC MARKETS FOR PURPOSES OF ANALYZING RETAIL COMPETITION?

A. The same product market is relevant for both analyses: bulk power. On balance, it appears that the geographic market relevant for the retail analysis is at least as broad as the geographic market used in the wholesale analysis. For the reasons just described, it is unlikely that the introduction of retail competition will lead to changes in physical flows that would narrow the market. The same capacity that constrains the ability of the merged applicants to raise prices under wholesale competition would also constrain their ability to increase prices under retail competition. In addition, the introduction of regional transmission tariffs and ISO are likely to broaden markets.

Q. IN LIGHT OF THESE CONSIDERATIONS, WHAT DO YOU CONCLUDE ABOUT THE MERGED ENTITY'S ABILITY TO EXERCISE MARKET POWER IN THE RELEVANT GEOGRAPHIC AREA?

A. Given that the product and geographic markets used to analyze retail competition are the same as (or potentially broader than) the markets relevant to the analysis of wholesale competition, the results are the same: the proposed merger raises no competitive concerns in the properly-defined regional market.

Q. EVEN IF THE REGIONAL MARKET IS COMPETITIVE, ARE THERE ANY CIRCUMSTANCES UNDER WHICH THE MERGED ENTITY

MIGHT BE ABLE TO EXERCISE MORE LOCALIZED MARKET POWER OVER RETAIL CUSTOMERS?

A. In theory, there are certain circumstances under which a firm might be able to strategically manipulate constraints on transfer capability in order to preclude competitive access and exercise localized market power. If a single firm owned all (or most) of the generation in a specific geographic region – e.g., its own control area – it might under some circumstances be able to restrict generation and increase prices without losing enough sales to render the price increase unprofitable. A firm might want to restrict output in order to be able to extract a higher price for the output it did supply, but raising its price would invite competition from alternative suppliers. Thus, the firm may wish to cut back output to the level that causes import capability to become constrained. This would effectively cap the amount of competitive generation that could enter the particular geographic area. Once this cap was reached, there would be no further constraint on the firm's ability to raise prices, other than the reduced purchases by consumers induced by the price increase. Two important assumptions for this scenario are that import capability is less than total demand in the area in question and that a single firm owns substantially all of the generating capacity in a control area. All else equal, the lower the ratio of net import capability to demand, the greater the incentive to engage in such behavior, as the firm will retain a higher proportion of sales at the high price.

Several important caveats must be borne in mind. First, the firm must balance the costs of engaging in such behavior against the potential gains. By cutting back on its generation to induce a certain quantity of imports, the utility necessarily sacrifices the sales it otherwise would have made inside the area under consideration. It is also important to note that, because transmission limits reflect *net* flows, in order to engage in such behavior, the firm must also forego its sales outside the specific geographic area. Thus, firms that export significant amounts of power are less likely to profit by manipulating transmission limits in this way. Similarly, the incentives to engage in such behavior generally will be greater for high-cost generators than for low-cost generators. A low-cost generator may be earning substantial profits when market prices exceed the marginal variable costs of some or all generators owned by that firm. In order to exploit transmission limits into a load pocket, the generator must reduce output significantly. The profits due to higher prices once imports reach the transmission limits must exceed the profits foregone on existing sales. The greater the profit margin on existing sales, the less likely is a generator to find strategic exploitation of transmission constraints profitable.

Q. CAN YOU ILLUSTRATE WHAT YOU MEAN BY STRATEGIC EXPLOITATION OF A TRANSMISSION CONSTRAINT WITH A NUMERICAL EXAMPLE?

Yes. Consider a hypothetical Utility A that owns all of the generation in a region that might correspond to its control area in the current environment.

Assume that demand in this region is equal to 100 MW. Further assume that total transmission capacity into this region is 30 MW, or 30 percent of demand in the region. If Utility A attempts to reduce generation by a small amount and increase price by a small amount when the net flow of power into this region is less than 30 MW, the attempt will probably be unsuccessful. As long as there is unused physical transmission capacity into the area in which Utility A owns generation, a reduction in generation and an increase in price will simply cause more power to flow into that area, rendering the price increase unprofitable. However, in this example, hypothetical Utility A might be able to engage in strategic manipulation, reducing its generation by 30 MW. Since 30 MW is the maximum amount of power that can flow into the region once the utility has reduced its generation by this amount (i.e., from the initial 100 MW down to less than 70 MW), it can begin increasing prices without fear of competition from imports. Once it has reduced generation to the level required to congest the transmission interface, the only limit on its ability to raise prices is the fact that, as prices increase, consumers may reduce their consumption of electricity.

Q. ARE "LOAD POCKETS" A CONCERN UNDER THE CURRENT REGULATORY REGIME?

A. Concerns about market power resulting from load pockets or strategic use of transmission are much less significant today given that retail prices are regulated. Currently, the owner of generation gains little or nothing in today's environment by withholding a substantial amount of output because the owner cannot raise price to the regulated customer. When all generating supplies are deregulated, owners of generation may be able to profit from withholding a sufficient amount of generation that transmission limits become binding, because the price they can charge for that output will not be limited by regulation.

Q. IN ANALYZING THE INCENTIVES TO ENGAGE IN STRATEGIC BEHAVIOR TO EXPLOIT TRANSMISSION LIMITS, OR LOAD POCKET ISSUES, DOES IT MATTER WHETHER THE AREA BEING EXAMINED IS A NET EXPORTER OR A NET IMPORTER OF POWER?

A. Yes, it does. One will be more concerned with load pocket issues and strategic exploitation of transmission limits in areas that are net importers of power in equilibrium than areas that are net exporters of power in equilibrium.

Q. WHY WILL ONE BE LESS CONCERNED WITH LOAD POCKET ISSUES OR STRATEGIC EXPLOITATION OF TRANSMISSION LIMITS IN AREAS THAT ARE NET EXPORTERS OF POWER?

A. Again, returning to our numerical example of a utility that owns all of the generation in an area with 100 MW of load and 30 MW of net import capacity, assume that this is an area with lower-cost generation than the region in which it operates. In this case, the entity owning all of the generation in this area would tend to be a net exporter of power. That is, generation in the area will exceed demand in the area.

Assume that in equilibrium there is 100 MW of load in the area in which Utility A owns all of the generation but Utility A is actually generating 120 MW because it is exporting 20 MW to areas with higher-cost generation. To strategically exploit the transmission limit of 30 MW into Utility A's control area, Utility A must reduce its generation by 50 MW before it can substantially increase price. Utility A cannot begin to increase prices substantially until the transmission limit of a 30 MW net flow of power into control area A is reached. This limit is not reached until Utility A has ceased to export 20 MW and reduced generation by an additional 30 MW (thereby increasing imports to 30 MW) to force the 30 MW net import limit to become binding. Thus the total required generation reduction is 50 MW. Thus, for purposes of examining market power, the effective net transfer capability into a region – or the amount of generation that Utility A would have to reduce before it could begin raising prices significantly – is equal to the sum of its net exports in equilibrium plus the net transfer capability into the region.

The situation is exactly the reverse for a utility that is a net importer of power in equilibrium. Again, assume that our hypothetical Utility A has a net transfer limit into the region of 30 MW and there is 100 MW of load in the region. Further assume that in equilibrium Utility A is generating 80 MW and 20 MW is being imported. Utility A would only have to reduce its generation by 10 MW (or 12.5 percent (10 MW ÷ 80 MW) before it could begin increasing prices without facing the threat of additional imports. This is in direct contrast to the net exporting utility, which is generating 120 MW in equilibrium and must reduce its generation by 50 MW or 41 percent (50 MW ÷ 120 MW) before it can raise prices without fear of the threat of imports defeating the price increase. In this example, the net exporting utility would have to forego profits on 50 MW of sales before it could begin increasing prices significantly. The net importing utility would have to forego profits on only 10 MW of sales before it could begin increasing prices significantly. Moreover, it is reasonable to assume that a net exporter of power is earning higher average profits on sales of power than a net importer. This is because the net exporter is more likely to own generating units with marginal operating costs significantly lower than the market price of power. Stated another way, low- cost utilities tend to be net exporters of power whereas high-cost utilities tend to be net importers. The net exporter not only foregoes profits on more sales, but the profits foregone on each unit of generation reduction are also likely to be greater. Thus, the cost of engaging in strategic exploitation of transmission limits is greater for a net importer than a net exporter. The profitability of strategic exploitation of transmission limits – and hence the likelihood of such exploitation actually occurring – is likely to be greater for a net importer than a net exporter.

Q. IF A SINGLE FIRM OWNED ALL OF THE GENERATING CAPACITY IN A "LOAD POCKET," COULD THAT FIRM PROFITABLY IMPOSE A "SMALL BUT SIGNIFICANT AND NON-TRANSITORY" INCREASE IN PRICE?

A. Not necessarily. It is quite possible that a small price increase would not be profitable because there might be sufficient import capability to render a small price increase unprofitable. As such, a load pocket is not necessarily an antitrust market under the *Merger Guidelines* approach to market definition.

The market power issue here is more likely to be a case of unilateral market power, in which only a large decrease in output and increase in price is profitable. The market power issue that arises from a load pocket is that a firm might spike prices sharply upward for a short period of time by withholding a substantial amount of capacity.

Q. ARE THE KCPL AND WESTERN RESOURCES CONTROL AREAS NET IMPORTERS OR NET EXPORTERS OF POWER?

A. The control areas operated by the two merging parties tend to be net exporters rather than importers of power. The combined company control area may be a net importer at the time of summer peak. The KCPL control area is a net importer during summer peak periods. This is shown in Schedule RMS-11 and Schedule RMS-12. Schedule RMS-11 comprises six pages and uses 1995 Form 714 data. Schedule RMS-12 uses 1996 data. Each schedule has two pages for KCPL, two pages for Western Resources, and two pages that show the results for the combined entity. For each month, I show monthly control area generation and control area load, as well as net MWH exports for that month. On the second page for each utility, I show monthly control area peaks and control area generation net at the time of peaks and exports.

The load data in Schedule RMS-11 and Schedule RMS-12 include all load in the control area, not just Western Resources' (or KCPL's) load. For example, the Western Resources control area load includes KEPCO's load. Control area generation includes all generation in the control area regardless of ownership. For example, the Western Resources control area generation includes all of the output of Wolf Creek (which is jointly owned by Western Resources, KCPL and KEPCO) and all of the output of Jeffrey Energy Center (including UtiliCorp's 320MW) but does not include Western Resources' interest in LaCygne.

In 1996 KCPL was a net exporter in every month. Monthly net exports from the KCPL control area ranged from a low of 130,696 MWH in July to a high of 606,500 MWH in October. This is an average hourly net export of 179 MW in July (130,696 MWH divided by 744 hours in July) to 815 MW per hour in October. Western Resources' was a net importer in two months of 1996 – February and March. In the remaining ten months, Western Resources' monthly net exports ranged from 163,416 MWH in April to 465,135 MWH in November. This is an average hourly net export rate of 227 MW per hour to 646 MW per hour.

In 1996 monthly net exports from the combined control area range from 162,803 MWH in March (or 219 MW per hour) to 947,681 MWH in November (or 1316 MW per hour).

It should also be noted that, as transmission prices fall, net exports from low-cost producers, including the merged entity, are likely to increase, thus diminishing any incentives the merged entity might have to strategically exploit transmission limits.

Q. CAN AN ENTITY OWNING MOST OR ALL OF THE CAPACITY IN A LOAD POCKET MAINTAIN PRICES SUBSTANTIALLY ABOVE COSTS FOR SUSTAINED PERIODS OF TIME?

A. The longer the period of time an entity attempts to increase prices by strategically exploiting transmission limits, the greater the reduction in output necessary to maintain high prices. The entity owning most or all of the generation in an area must first reduce output by an amount equal to the sum of net import capability plus net exports in the initial equilibrium in order to increase prices.

The output reduction required to achieve a given price increase is greater if consumers reduce their demand as prices increase. The longer the price increase is in effect, the greater the reduction in demand due to the price increase, and the less likely that the price increase will prove profitable.

Q. WHAT TRANSFER LIMITS ARE IMPORTANT FOR DETERMINING WHETHER OR NOT A UTILITY OWNING ALL OR MOST OF THE GENERATION IN A SPECIFIC AREA CAN STRATEGICALLY EXPLOIT TRANSMISSION CONSTRAINTS?

A. The transmission limits that are important for this analysis are the simultaneous import capability into each utility's control area on a pre-merger basis and the simultaneous import capability into the combined entity's control area on a post-merger basis.

Q. **WHAT DO YOU MEAN BY SIMULTANEOUS IMPORT CAPABILITY?**

A. By simultaneous import capability, I mean the total amount of power that could physically flow into a utility's control area without violating thermal, voltage, or first contingency limits. It is important to note that this number is not the sum of the individual transfer capabilities from each of the directly interconnected utilities.

Q. **IS SIMULTANEOUS IMPORT CAPABILITY INTO A UTILITY'S CONTROL AREA A CALCULATION THAT IS MADE IN THE NORMAL COURSE OF BUSINESS BY EITHER WESTERN RESOURCES OR KCPL?**

A. No, it is not. At my request, however, KCPL and Western Resources conducted load flow studies to determine the simultaneous import capability at the time of summer peak. Mr. Dixon's supplemental direct testimony discusses those studies in more detail.

Q. **WHY DID YOU PERFORM YOUR LOAD POCKET ANALYSIS BASED ON SUMMER PEAK CONDITIONS?**

A. If there are incentives for either of the two merging parties to reduce generation to strategically exploit transmission limits, those incentives are likely to be greatest during the summer peak periods. The incentives for the Applicants to engage in strategic exploitation of transmission limits are likely to be much weaker during lower load periods. During lower load periods, the Applicants are more likely to be net exporters of power. As I indicated earlier, a net exporter of power is less likely to profit from strategic exploitation of transmission limits. During summer peak periods there is more load than during seasonal or daily off-peak periods. The greater the load when prices are increased, the greater the potential profits due to a price increase.

Finally, the lower the load level, the greater the likely percentage reduction in output necessary to increase imports to the level that the transmission system becomes constrained. If simultaneous import capability is similar in peak versus off-peak periods, the ratio of import capability to load is greater during off-peak periods than during on-peak periods. The greater the percentage reduction in output required to implement a price increase, the less likely it is that a price increase will prove profitable.

Q. BRIEFLY DESCRIBE YOUR UNDERSTANDING OF HOW THESE STUDIES ARE CONDUCTED.

A. These studies are conducted using computer models known as load-flow models. In order to determine transfer limits, one makes a series of computer model runs in which one lowers generation in the KCPL or Western Resources control area and raises generation in other control areas until a transmission constraint is reached. The import capability into the KCPL or Western Resources control area is determined to be the load-flow or import level into the KCPL or Western

Resources control area at which such a constraint is reached. Mr. Dixon describes these studies in more detail in his supplemental direct testimony.

Q. ARE THE RESULTS OF THESE STUDIES SENSITIVE TO ALTERNATIVE ASSUMPTIONS?

A. Yes, they can be. Mr. Dixon discusses this issue in his testimony. Recall I said that one conducts these studies by assuming a reduction of the generation in the receiving control area and an increase in generation in other control areas. Exactly which generators have their output reduced and which have their outputs increased can have significant effects on the results of the study. At my request, KCPL and Western Resources performed these studies under three alternative assumptions. The first was the methodology that the SPP currently uses for determining first-contingency incremental transfer capability between control areas. In this methodology, the output of all generators other than nuclear units in the receiving control area is reduced by an equal proportion regardless of their actual cost. That is, one starts with a peak-load condition in which a sufficient number of generators are running in the control area in order to meet control area load plus net imports or exports. One then reduces the output of combustion turbines by the same percentage as one reduces the output of low-cost units such as the Jeffrey Energy Center.

The second assumption used in the model runs was that generation in the KCPL and Western Resources area was reduced on an approximate economic dispatch basis. That is, in computing the net simultaneous import capability, the generation of the highest-cost units in the KCPL and/or Western Resources service area was reduced first, followed by reductions in generation from low-cost units. If a utility were reducing output in order to raise prices, it would generally tend to reduce the output of its highest-cost units before it would reduce the output of its lowest-cost unit.

The final set of calculations was made by assuming that the generation in the receiving control area was reduced in a manner calculated to maximize or approximately maximize net import capability into the region. If net import capability into a region could be increased by operating a high-cost unit rather than reducing the output of that unit, that unit was assumed to continue to operate. This third scenario is one way of modeling the potential impacts of an ISO with the ability to redispatch units in order to maximize transmission import capability during times in which constraints are likely to be encountered. This set of calculations does not reflect all of the options that might be available to an ISO. The load flow studies were conducted assuming that only Western Resources or KCPL generation could be adjusted in order to relieve transmission constraints. In some cases, the limiting factor on imports to Western Resources or KCPL is a transmission facility in another control area. The load flow studies did not adjust generation or other systems to relieve constraints. An ISO might be able to adjust generation in all control areas to relieve constraints.

Finally, these results reflect the transfer limits under first contingency conditions associated with current operation of the transmission system. As I discussed earlier, implementation of retail competition will probably involve formation of an ISO. Such an ISO might operate the transmission system differently compared to current operations.

Q. WHAT WERE THE RESULTS OF THESE STUDIES?

For the KCPL control area, the Western Resources control area, and the combined company control area, Schedule RMS-13 shows the total simultaneous import capability at summer peak based upon these studies. The three columns refer to the three alternative assumptions used in the load flow studies. Again, these assumptions were: 1) SPP methodology for determining which generators reduce output, 2) economic dispatch, and 3) adjustment generation to maximize net import capability. The simultaneous import capability is calculated as follows. Generation in the control area is reduced until a thermal or voltage constraint under first contingency conditions is reached. The net import capability equals control area load less generation in the control area at the point a constraint or limit is reached.

The generation figures used in these calculations include all of the generation in the control area regardless of who owns that generation. For example, the generation in the Western Resources control area includes all of Wolf Creek and all of the generation owned by cities such as McPherson. It does not include the LaCygne generation owned by Western Resources that is in

KCPL's control area. The load is total control area load, not just Western Resources' load.

These calculations show the sensitivity of the results to alternative assumptions. The KCPL net import capability ranges from 1,644 MW to 2,414 MW, depending on whether the SPP methodology is used or whether generation is redispatched to maximize import capability. The simultaneous import limit to the Western Resources control area is 887 MW using the SPP methodology and 1,887 MW based on redispatching Western Resources' units to maximize import capability.

The simultaneous import limit for the combined control area is shown as the same amount – 1,606 MW – in both the SPP methodology and the maximize-imports cases, because in both cases the limiting factor is a line in the Union control area.

Q. HOW CAN ONE USE THOSE RESULTS TO ANALYZE THE LOAD POCKET ISSUE?

A. Such an analysis is outlined in Schedule RMS-14, which consists of three pages. Page one uses the simultaneous import limits calculated using the SPP methodology. Page two shows the calculations assuming economic dispatch. Page three uses the simultaneous import limits calculated by adjusting Western Resources and KCPL generation in order to maximize imports into their control areas.

Column 1 is control area load and Column 2 is control area generation regardless of who actually owns the generation.

Columns 3 and 4 separate generation within the control area into generation owned by the control area operator and generation owned by others. The generation refers to the output of generators in the control area at the time of summer peak used in the base case of the load flow study. In the KCPL case, generation owned by others includes Western Resources' share of LaCygne and the Iatan capacity co-owned by St. Joseph Light & Power and Empire. The generation owned by others in the Western Resources control area includes KCPL and KEPCO's share of Wolf Creek, UtiliCorp's share of Jeffrey, and generation owned by cities in the Western Resources control area. The generation owned by others in the combined case is lower than either of the pre-merger cases because, post-merger, all of LaCygne and all but 85 MW of Wolf Creek will be owned by the merged company.

Column 5 shows net exports in the base case. Only firm transactions are included in the data input to the load flow models. Column 6 shows simultaneous transfer capability. Column 7, "Potential Loss," is the sum of the net export capability and the simultaneous transfer capability into the control area. This is the amount by which the control area operator (i.e., Western Resources or KCPL) would have to reduce its output before a transfer limit was reached. Column 8 expresses this potential loss as a percentage of the generation owned by the control area operator.

Pre-merger, KCPL would have to reduce its generation by 72 percent before it became an import-constrained system. In order to raise prices by strategically exploiting a transmission constraint, KCPL would first have to reduce its generation by 72 percent.

The Western Resources results show total control area generation of 5,239 MW, net exports of 413 MW, and a simultaneous transfer capability into the utility's control area of 887 MW. The potential loss is 1,300 MW (the sum of net exports of 413 MW and simultaneous transfer capability of 887 MW) when the SPP methodology is used to calculate simultaneous import capability. The potential loss as a percent generation owned by Western Resources (and operating at the time of peak) is 32 percent. This means that if Western Resources reduced its generation by 32 percent it could increase prices without the threat of additional imports.

When the Western Resources control area simultaneous import limit is calculated, assuming that generation is altered to maximize net imports, the potential loss as a percent of Western Resources generation is 57 percent. This means that Western Resources would have to reduce its output by 57 percent before it could begin increasing prices without fear of competition from imports.

In the combined case, the potential loss is 26 percent of the combined company's generation using either the SPP methodology or the maximize imports case. This means that if the combined company reduced generation by 26 percent, it could begin increasing prices without fear of additional competition from imports.

Q. DO THESE CALCULATIONS INDICATE THAT THERE ARE LOAD POCKET ISSUES ASSUMING RETAIL COMPETITION?

A. The transfer limits in current transmission guidelines indicate that with or without the merger, the Western Resources control area and the combined company control area is a "load pocket." The KCPL control area may be a load pocket with or without the merger. The Western Resources control area pre-merger and the combined control area may present localized market power concerns during summer peak periods due to the potential for profitable strategic exploitation of transmission limits. The KCPL control area, pre-merger, is less likely to present such localized market power issues.

These conclusions are predicated on simultaneous import limits calculated under first contingency conditions for the transmission system as it exists today and as it is operated today. Mr. Dixon discusses the caveats that should be placed on the use of current load flow studies. To the extent that transmission system operations and/or capacity change in the future as a result of formation of an ISO, these conclusions could change also.

Q. WHY DO YOU SAY THAT PRE-MERGER, LOAD POCKET ISSUES ARE NOT LIKELY TO RAISE MARKET POWER CONCERNS IN THE KCPL CONTROL AREA, BUT MIGHT RAISE MARKET POWER CONCERNS IN THE WESTERN RESOURCES CONTROL AREA?

A. Load pockets only raise market power concerns if an entity owning most of the generation within that load pocket can profit by reducing output and increasing prices. This requires a comparison of the increased profits due to a price increase versus the profits lost due to reducing output. Schedule RMS-14 indicates that KCPL would have to reduce output of its generators by 70 percent or more in order to raise prices by strategically exploiting a transmission limit. Western Resources would have to reduce the output of its generators by 32 percent in order to raise prices by strategically exploiting transmission limits, when transmission limits are calculated using the existing SPP methodologies.

Although the exact calculation of the profitability of such an output reduction is likely to depend on numerous factors, if it is necessary to reduce output by 70 percent in order to increase prices, such an output reduction is not likely to be profitable. If the required output reduction is 25-35 percent of output, such an output reduction might be profitable.

Q. DOES THIS MEAN THERE WILL BE MARKET POWER PROBLEMS IF RETAIL COMPETITION IS IMPLEMENTED?

A. The degree to which there will be market power issues when retail competition is implemented will depend in large measure on other changes that are part of the retail competition structure. The timing of any such issues will also depend on the details of implementation. If retail choice is phased in gradually, it may be a number of years before sufficient additional load is added at unregulated prices to provide incentives for the utility to attempt to raise prices. It should also be noted that during any phase-in, regulators presumably will be able to exercise control over the utility's pricing. There are several mitigation factors that could substantially reduce the likelihood of market power concerns related to load pockets. These mitigation factors could be integrated into the implementation of retail competition. Finally, the transfer limits that I have used in my analysis are based on the first contingency conditions for the transmission system as it exists and is operated today. To the extent that an ISO would be part of any implementation of retail competitor, and the formation and operation of the ISO would lead to different transfer limits, these conclusions would change.

Q. WHAT ARE SOME OF THESE MITIGATION MEASURES THAT MIGHT BE PART OF IMPLEMENTATION OF RETAIL COMPETITION?

A. There are several. The first is that there may be cost-effective ways to increase transmission capacity, thereby eliminating some transmission constraints and reducing the likelihood of transmission problems.

The second is that the transmission system could be operated with or by a strong ISO that is able to re-dispatch units to eliminate transmission constraints and/or reduce the frequency with which transmission limits prevent otherwise economic transactions from occurring.

The third potential mitigation measure would be that the ISO could require the largest generators within a load pocket to supply generation at some pre-determined level (i.e. a price that could not be influenced by withholding capacity) whenever there is no additional import capability into the area in which that generator owns a significant portion of the total generation. Such a mitigation measure would reduce the profitability, and hence the likelihood, of strategic exploitation of transmission limits.

The fourth potential mitigation measure is stranded cost recovery mechanisms may require that profits from sales of power from units receiving stranded cost payments be used to mitigate stranded costs. This reduces incentives to exploit transmission limits because it reduces the amount of capacity on which the profits of the price increase can be realized. Finally, some generation divestiture may be part of any movement towards retail competition – not necessarily to address market power concerns alone, but also as a method of resolving stranded cost issues.

Q. ARE YOU PROPOSING OR RECOMMENDING ANY SPECIFIC MITIGATION MEASURES IN THIS PROCEEDING?

A. No I am not.

Q. WHY NOT?

A. There are several reasons. First of all, the potential market power issues I have identified are not attributable solely to the merger. These are issues that are associated with retail competition whether or not the merger occurs. These issues may occur with the implementation of retail competition regardless of what is done in this proceeding. Moreover, the same issues probably arise in the case of other utilities subject to the jurisdiction of the Commission. Thus, these issues will need to be considered and are more properly considered when retail competition is actually introduced, rather than as part of this merger proceeding.

A second reason for not considering mitigation measures now is that retail competition will not begin in Missouri in the next few years. Substantially more information in terms of the magnitude of the competitive issues and their potential resolution will become available in the next few years. For example, one will be able to observe experience in other states where the same issue might arise.

The transfer limits that result from current load flow studies reflect the first contingency conditions for the transmission system as it exists and as it is operated today. Mr. Dixon discusses the caveats that should be placed on the results of current load flow studies. There are plans underway to formulate an ISO for the SPP or for the SPP plus MAPP. As I have indicated earlier in my testimony, retail competition is likely to involve implementation of an ISO. The transfer limits and transmission capacities which are actually relevant for assessing retail competition are those with an ISO in place, not those prior to the implementation of the ISO. Although the implementation of an ISO does not change the law of physics, it may lead to changes in the way transmission systems are operated and planned and, hence, substantially different transmission constraints or limits than those observed today. Since the issues I have discussed will arise with or without the merger when retail competition is introduced, it makes sense to take advantage of the substantial additional information that will become available over the next couple of years.

My analysis of market power issues in this proceeding assumes full deregulation of generation and full implementation of retail competition. It is possible that retail competition is phased in gradually and regulation of some form of existing generators continues during this phase-in period. Such a phase-in may reduce the concern over localized market power because there would be limits on the ability of firms to increase prices while regulation of one form or another continued.

Finally, any measures implemented to reduce concerns over market power under retail competition are likely to be part of an overall restructuring plan. It makes no sense to try and discuss mitigation measures piecemeal outside of a comprehensive and constructive plan to implement retail competition. The purpose of this proceeding is not to design a complete retail competition plan when it is not likely that retail competition will even be implemented until three to five years from now.

Q. THANK YOU.

AFFIDAVIT OF DR. ROBERT M. SPANN

STATE OF District of)
) ss.
COUNTY OF Columbia)

Dr. Robert M. Spann of lawful age, on his oath, states that he has participated in the preparation of the foregoing direct testimony in question-and-answer form to be presented in the above case; that he prepared the attached schedules; that the answers in the foregoing direct testimony were given by him; that he has knowledge of the matters set forth in such answers and schedules, and that such matters are true and correct to the best of his knowledge and belief.

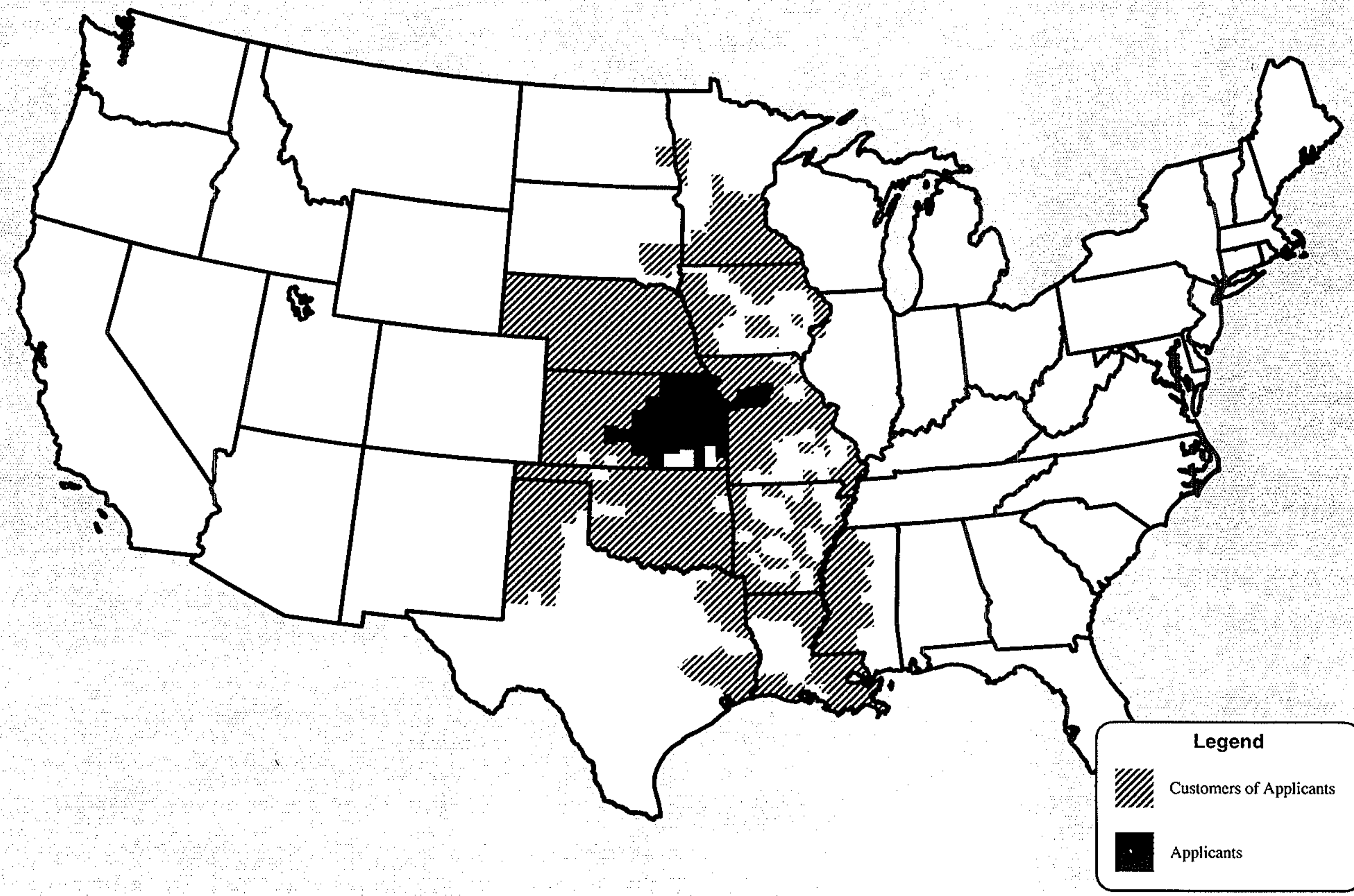
Dr. Robert M. Spann

Subscribed and sworn to before me this 12th day of December, 1997.

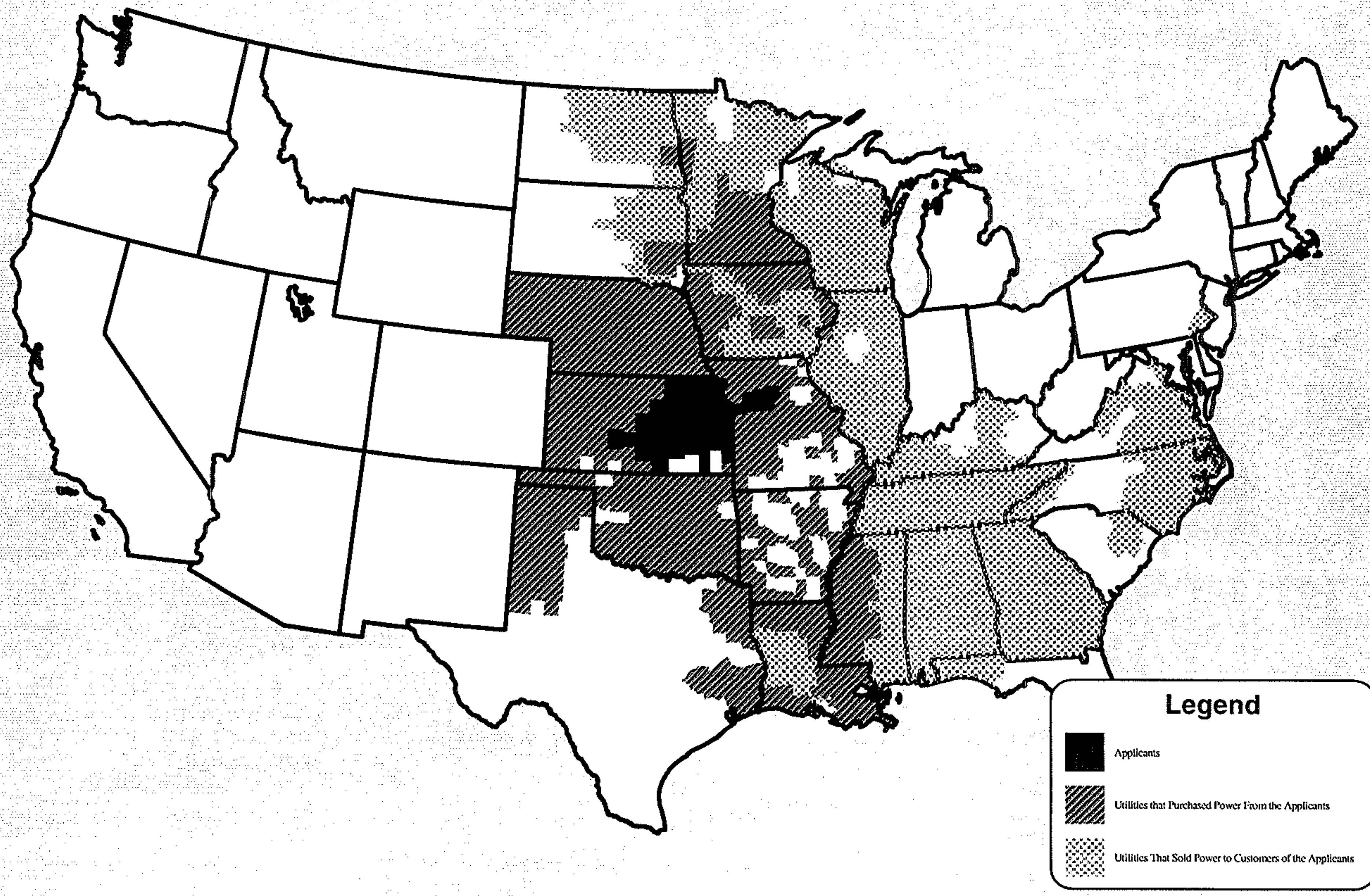
Notary Public

My Commission expires May 31, 2001

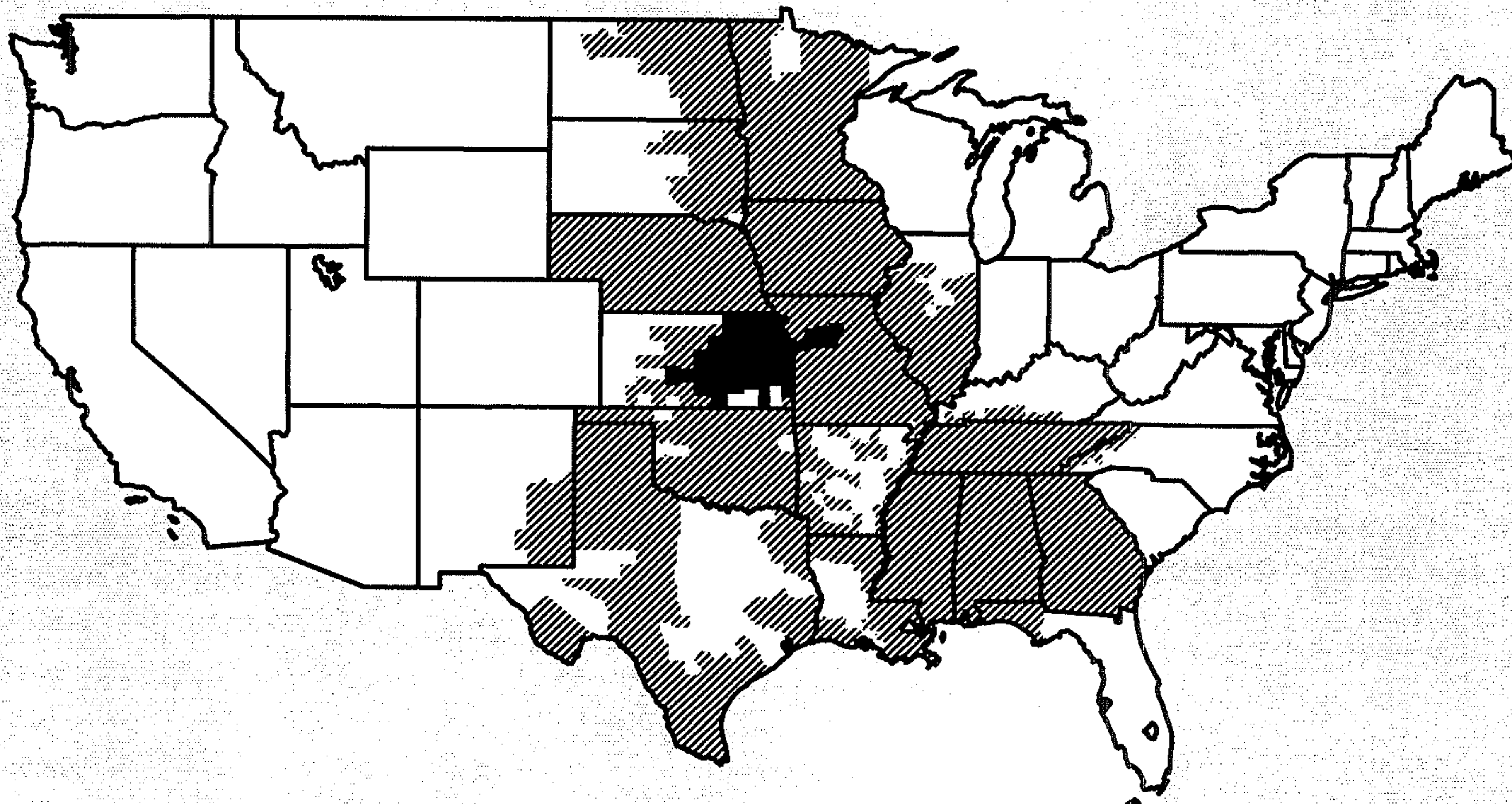
Service Areas of Utilities That Purchased Power from the Applicants



Service Areas of Utilities That Sold Power to Customers of the Applicants



Service Areas of Utilities in Relevant Geographic Market



Capacity, Market Share, and HHI
Total Capacity
Regional Market: Southwest Power Pool + Union + MAPP[1]

Purchaser	Total Generating Capacity (MW)	Market Share	HHI
Kansas City Power and Light	3,134	4.11%	17
Western Resources	5,333	6.99%	49
Entergy Electric System	22,242	29.16%	850
Union Electric Company / CIPSCO	10,741	14.08%	198
Central & South West Services [2]	8,221	10.78%	116
Oklahoma Gas & Electric	5,638	7.39%	55
Central Louisiana Electric Company	2,633	3.45%	12
Associated Electric Cooperative, Inc.	2,547	3.34%	11
Southwestern Power Administration	2,079	2.72%	7
Arkansas Rural Electric Coop	1,788	2.34%	5
Utilicorp	1,625	2.13%	5
Cajun Electric Power Cooperative	1,613	2.11%	4
Grand River Dam Authority	1,280	1.68%	3
MAPP [1]	1,200	1.57%	2
Western Farmers Electric Cooperative	1,093	1.43%	2
Empire District Electric Company	723	0.95%	1
Board of Public Utilities - KCK	676	0.89%	1
City Utilities, Springfield, MO	663	0.87%	1
City of Lafayette, LA	580	0.76%	1
Sunflower Electric Power Corporation	522	0.68%	0
St. Joseph Light & Power Co.	382	0.50%	0
Louisiana Energy & Power Authority	350	0.46%	0
Southwestern Public Service [3]	300	0.39%	0
City of Independence, MO	288	0.38%	0
KAMO Electric Cooperative	200	0.26%	0
Oklahoma Municipal Power Authority	158	0.21%	0
Northeast Texas Electric Cooperative	117	0.15%	0
City of Clarksdale, MS	60	0.08%	0
MidWest Energy	32	0.04%	0
City of Alexandria, LA	8	0.01%	0
Sam Rayburn G & T, Inc. [4]	55	0.07%	0
City of Sikeston, MO [5]		0.00%	-
Total	**76,279**	**100.00%**	**1,342**
Change in HHI Due to Merger			**57**
Post-Merger HHI			**1,399**

Notes: [1] Constrained to 1200 MW due to transmission constraints.
[2] Includes 800 MW of CSW - ERCOT Capacity
[3] Constrained to 300 MW due to transmission constraints.
[4] From SPP 1997 OE-411.
[5] Included in Associated Electric Cooperative's control area.

Sources: 1995 EIA Form 860.
1997 SPP OE-411.

Capacity, Market Share, and HHI
Coal and Nuclear Capacity
Regional Market: Southwest Power Pool + Union Electric + MAPP[1]

Utility	Coal (MW)	Nuclear	Total	Market Share	HHI
Kansas City Power & Light Company	2,083	548	2,631	6.50%	42
Western Resources	3,241	548	3,790	9.36%	88
Arkansas Electric Cooperative Corporation	1,408	-	1,408	3.48%	12
Associated Electric Cooperative, Inc.	2,502	-	2,502	6.18%	38
Cajun Electric Power Cooperative	1,393	-	1,393	3.44%	12
CSW-SPP[2]	3,537	-	4,337	10.71%	115
Central Louisiana Electric Company	482	-	482	1.19%	1
City of Alexandria, LA	-	-	-	0.00%	-
City of Clarksdale, MS	-	-	-	0.00%	-
City of Lafayette, LA	262	-	262	0.65%	0
City Power & Light, Independence, MO	131	-	131	0.32%	0
City Utilities, Springfield MO	413	-	413	1.02%	1
Empire District Electric Company	383	-	383	0.95%	1
Entergy	2,506	3,424	5,931	14.65%	215
Grand River Dam Authority	810	-	810	2.00%	4
KAMO Electric Cooperative	200	-	200	0.49%	0
Kansas City Board of Public Utilities	572	-	572	1.41%	2
Louisiana Energy & Power Authority	105	-	105	0.26%	0
Midwest Energy	-	-	-	0.00%	-
Northeast Texas Electric Cooperative	117	-	117	0.29%	0
Oklahoma Gas & Electric Company	2,530	-	2,530	6.25%	39
Oklahoma Municipal Power Authority	92	-	92	0.23%	0
Southwestern Public Service Company[3]	2,146	-	300	0.74%	1
St. Joseph Light & Power Company	218	-	218	0.54%	0
Sunflower Electric Power Corporation	325	-	325	0.80%	1
Union/CIPSCO[4]	7,948	1,125	9,073	22.41%	502
Utilicorp	880	-	880	2.17%	5
Western Farmers Electric Cooperative	408	-	408	1.01%	1
MAPP[1]			1,200	2.96%	9
Total	**34,692**	**5,646**	**40,493**	**100.00%**	**1,089**
Change in HHI due to Merger					**122**
Post-Merger HHI					**1,210**

Notes: [1] Total capacity is 1200 MW to account for transmission constraints.
[2] Total capacity has been increased by 800 MW to account for CSW-ERCOT.
[3] Total capacity has been changed to 300 MW to account for transmission constraints.
[4] Capacities account for the merger between Union and CIPSCO.

Source: 1995 EIA Form 860.

Analysis of Concentration: Economic Capacity
Case 1: Delivered Prices Measured at Utility's Border or SPP Border

Economic Capacity						
	Market Excluding Southern		Market Including Southern & TVA		Market Excluding Southern & TVA	
Price	Post-Merger HHI	Change in HHI	Post-Merger HHI	Change in HHI	Post-Merger HHI	Change in HHI
14	2,003	73	1,672	49	1,413	193
20	1,424	78	1,250	63	928	167
25	1,530	34	1,384	22	1,055	74
35	1,281	32	1,279	19	1,029	60

Note: [1] Economic capacity for each utility in SPP (as of Spann FERC filing) based on its own energy cost and transmission tariff. Economic Capacity for MAPP, MAIN, and SERC utilities based on least cost destination with the SPP.

Analysis of Concentration: Economic Capacity
Case 2: Delivered Prices at Entergy Border

Economic Capacity						
	Market Excluding Southern		Market Including Southern & TVA		Market Excluding Southern & TVA	
Price	Post-Merger HHI	Change in HHI	Post-Merger HHI	Change in HHI	Post-Merger HHI	Change in HHI
14	2,140	36	1,765	24	1,436	101
20	1,846	42	1,578	27	1,267	104
25	1,554	34	1,496	19	1,089	74
35	1,351	27	1,316	16	1,242	50

Analysis of Concentration: Economic Capacity
Case 3: Delivered Prices Measured at Utility's Border or SPP Border, Assuming Zero Transmission Cost [1]

Economic Capacity						
	Market Excluding Southern		Market Including Southern & TVA		Market Excluding Southern & TVA	
Price	Post-Merger HHI	Change in HHI	Post-Merger HHI	Change in HHI	Post-Merger HHI	Change in HHI
14	1,281	129	1,140	97	1,067	240
20	1,579	35	1,389	24	1,046	80
25	1,381	30	1,361	18	961	62
35	1,323	29	1,293	18	1,216	52

Note: [1] Economic capacity for each utility in SPP (as of Spann FERC filing) based on its own energy cost, assuming zero transmission cost. Economic Capacity for MAPP, MAIN, and SERC utilities based on costs delivered to the border of SPP.

Analysis of Concentration: Marginal Economic Capacity
Case 1: Delivered Prices Measured at Utility's Border or SPP Border

Marginal Economic Capacity						
	Market Excluding Southern		Market Including Southern & TVA		Market Excluding Southern & TVA	
Price Range	Post-Merger HHI	Change in HHI	Post-Merger HHI	Change in HHI	Post-Merger HHI	Change in HHI
14-25	1,322	16	1,315	10	1,167	43
25-35	792	6	1,708	3	1,521	6
14-20	962	69	1,093	69	881	114
20-25	2,101	0	2,044	0	2,749	0

Note: [1] Economic capacity for each utility in SPP (as of Spann FERC filing) based on its own energy cost and transmission tariff. Economic Capacity for MAPP, MAIN, and SERC utilities based on least cost destination with the SPP.

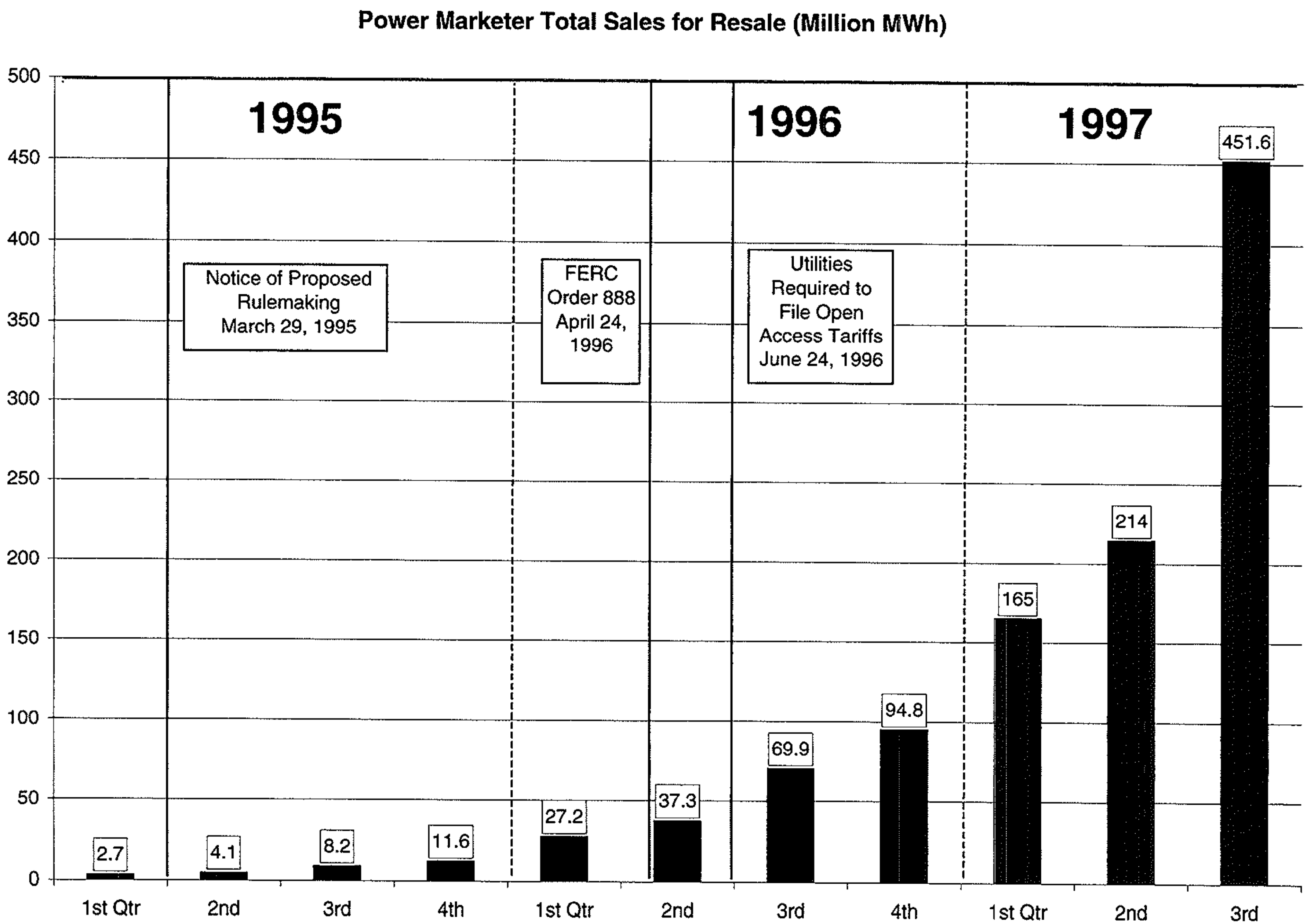
Analysis of Concentration: Marginal Economic Capacity
Case 2: Delivered Prices at Entergy Border

Marginal Economic Capacity						
	Market Excluding Southern		Market Including Southern & TVA		Market Excluding Southern & TVA	
Price Range	Post-Merger HHI	Change in HHI	Post-Merger HHI	Change in HHI	Post-Merger HHI	Change in HHI
14-25	1,355	27	1,454	14	1,231	70
25-35	2,137	3	1,818	2	2,137	3
14-20	1,700	38	1,484	24	1,525	109
20-25	949	0	2,508	0	905	0

Analysis of Concentration: Marginal Economic Capacity
Case 3: Delivered Prices Measured at Utility's Border or SPP Border, Assuming Zero Transmission Cost [1]

Marginal Economic Capacity						
	Market Excluding Southern		Market Including Southern & TVA		Market Excluding Southern & TVA	
Price Range	Post-Merger HHI	Change in HHI	Post-Merger HHI	Change in HHI	Post-Merger HHI	Change in HHI
14-25	1,643	0	1,756	0	1,520	0
25-35	2,647	7	2,472	5	3,044	7
14-20	2,174	0	1,836	0	1,977	0
20-25	1,307	0	3,000	0	1,970	0

Note: [1] Economic capacity for each utility in SPP (as of Spann FERC filing) based on its own energy cost, assuming zero transmission cost. Economic Capacity for MAPP, MAIN, and SERC utilities based on costs delivered to the border of SPP.



Sources: Edison Electric Institute, Regulatory Research Services
FERC Order No. 888

Western Resources
Non-Firm Wholesale Sales for Resale
And Short-Term Firm Sales, 1995 and 1996
Power Marketers vs. Utilities

	1995	1996	Percent Change
Customers			
Total	35	51	45.71%
Power Marketers	3	18	500.00%
Utilities	32	33	3.13%
MWH Sold			
Total (MWH)	2,508,407	3,846,384	53.34%
To Power Marketers (MWH)	30,240	1,106,945	3560.53%
To Utilities (MWH)	2,478,167	2,739,439	10.54%
Sales			
Total	$50,356,373	$84,247,034	67.30%
Power Marketers	$546,900	$18,463,120	3275.96%
Utilities	$49,809,473	$65,783,914	32.07%

Sources: Kansas Power & Light's 1995 and 1996 FERC Form 1.
Kansas Gas and Electric's 1995 and 1996 FERC Form 1.
Power Markets Week, QPM Database.

Kansas City Power & Light
Non-Firm Wholesale Sales for Resale
And Short-Term Firm Sales, 1995 and 1996
Power Marketers vs. Utilities

	1995	1996	Percent Change
Customers			
Total	30	42	40.00%
Power Marketers	4	14	250.00%
Utilities	26	28	7.69%
MWH Sold			
Total (MWH)	3,663,721	3,666,691	0.08%
To Power Marketers (MWH)	147,080	368,927	150.83%
To Utilities (MWH)	3,516,641	3,297,764	-6.22%
Sales			
Total	$57,978,311	$60,832,175	4.92%
Power Marketers	$2,165,585	$5,816,340	168.58%
Utilities	$55,812,726	$55,015,835	-1.43%

Source Kansas City Power & Light Co.'s 1995 and 1996 FERC Form 1.
Power Markets Week, QPM Database.

Top Ten Customers
Western Resources
Non-Firm Wholesale Sales for Resale
And Short-Term Firm Sales, 1995

Buyer	Statistical Classification	MWH Sold	Total Charges ($)	Cost Per MWH ($)
Midwest Energy	OS	724,346	13,620,692	18.80
Oklahoma Municipal Power Agency	OS	320,796	6,470,874	20.17
Empire District Electric Company	OS	217,836	4,903,861	22.51
Chanute, KS	OS[1]	154,477	3,097,608	20.05
Winfield, KS	OS[1]	112,756	2,268,064	20.11
Missouri Public Service (Utilicorp)	OS	111,504	2,177,928	19.53
Coffeyville, KS	OS[1]	108,499	2,142,561	19.75
Oklahoma Gas & Electric Company	OS	93,112	1,423,543	15.29
Iola, KS	OS[1]	87,747	1,781,298	20.30
Wellington, KS	OS[1]	66,367	1,338,570	20.17

Notes: [1] Supplemental Energy

Sources: Western Resources' 1995 FERC Form 1.
Kansas Gas & Electric Company's 1995 FERC Form 1.

Top Ten Customers
Western Resources
Non-Firm Wholesale Sales for Resale
And Short-Term Firm Sales, 1996

Buyer	Statistical Classification	MWH Sold	Total Charges ($)	Cost Per MWH ($)
Midwest Energy, Inc.	OS	801,160	23,056,460	28.78
Louisville Gas & Electric Marketing	OS	526,700	8,688,934	16.50
Empire District Electric Company	OS	321,607	8,242,599	25.63
Enron Power Marketing	OS	174,407	2,977,557	17.07
Oklahoma Gas & Electric Company	OS	167,635	2,934,873	17.51
Chanute, KS	OS	164,575	3,640,878	22.12
Coffeyville, KS	OS	130,855	2,745,418	20.98
Public Service of Oklahoma	OS	122,982	2,081,956	16.93
Louis Dreyfus Electric Power	OS	122,499	1,791,550	14.63
Iola, KS	OS	94,217	2,049,544	21.75

Sources: Western Resources' 1996 FERC Form 1.
Kansas Gas & Electric Company's 1996 FERC Form 1.

Top Ten Customers
Kansas City Power & Light Company
Non-Firm Wholesale Sales for Resale
And Short-Term Firm Sales, 1995

Buyer	Statistical Classification	MWH Sold	Total Charges ($)	Cost Per MWH ($)
Union Electric Company	OS [1]	1,729,771	27,531,222	15.92
Arkansas Rural Electric Cooperative	OS [2]	285,210	3,227,403	11.32
Empire District Electric Company	OS [1]	253,887	3,503,463	13.80
Associated Electric Cooperative, Inc.	OS [1]	253,132	3,521,646	13.91
Missouri Public Service Company	OS [1]	158,092	2,275,054	14.39
Kansas City Board of Public Utilities	OS [1]	117,321	2,124,399	18.11
St. Joseph Light & Power Company	OS [1]	111,843	1,806,467	16.15
Northern States Power Company	OS [1]	107,428	2,215,038	20.62
City of Marshall, MO	OS [1]	105,046	1,803,436	17.17
Louisville Gas & Electric Marketing	OS [2]	64,000	927,464	14.49

Notes: [1] The service to these customers is long-term service subject to availability.
[2] FERC Rate is Supplement #13 to WSPP Rate Schedule FERC #1.

Source: Kansas City Power & Light Company's 1995 FERC Form 1, pages 310 - 311.3.

Top Ten Customers
Kansas City Power & Light Company
Non-Firm Wholesale Sales for Resale
And Short-Term Firm Sales, 1996

Buyer	Statistical Classification	MWH Sold	Total Charges ($)	Cost Per MWH ($)
Union Electric Company	OS	1,256,371	20,661,257	16.45
Empire District Electric Company	OS [1]	523,426	8,599,566	16.43
Associated Electric Cooperative, Inc.	OS [1,2]	289,739	4,190,656	14.46
Arkansas Rural Electric Cooperative	OS [2]	286,800	3,421,715	11.93
Enron Power Marketing Inc.	OS [2]	180,353	2,708,395	15.02
Kansas City Board of Public Utilities	OS [1]	161,790	3,658,163	22.61
Entergy Electric System	OS [2]	161,070	2,865,679	17.79
City of Marshall, MO	OS [1]	109,610	1,866,558	17.03
Louisville Gas & Electric Marketing	OS [2]	105,545	1,625,830	15.40
Missouri Public Service Company	OS	99,638	1,561,654	15.67

Notes: [1] The service to these customers is long-term service subject to availability.
[2] FERC Rate is Supplement #13 to WSPP Rate Schedule FERC #1.

Source: Kansas City Power & Light Company's 1996 FERC Form 1, pages 310 - 311.4.

Monthly Generation, Load and Net Exports

Kansas City Power & Light Company

1995

(MWH)

Month	Generation (1)	Load (2)	Net Exports (3)=(1)-(2)
January	1,474,321	994,852	479,469
February	1,206,010	993,302	212,708
March	1,331,078	757,873	573,205
April	1,245,443	861,352	384,091
May	1,216,043	880,296	335,747
June	1,284,790	1,008,835	275,955
July	1,339,449	1,509,450	-170,001
August	1,430,556	1,592,829	-162,273
September	1,247,702	1,137,772	109,930
October	1,248,997	1,048,167	200,830
November	1,422,781	839,612	583,169
December	1,405,664	1,013,403	392,261

Source: Kansas City Power & Light Company's 1995 FERC Form 714.

Generation, Load, and Net Exports at Monthly Peak

Kansas City Power & Light Company

1995

(MW)

Month	Generation (1)	Load (2)	Net Exports (3)=(1)-(2)
January	2,431	1,866	565
February	2,073	1,778	295
March	2,189	1,797	392
April	1,854	1,626	228
May	1,960	1,930	30
June	2,236	2,640	-404
July	2,520	2,935	-415
August	2,247	2,965	-718
September	2,169	2,686	-517
October	1,974	1,927	47
November	2,092	1,726	366
December	2,398	1,928	470

Source: Kansas City Power & Light Company's 1995 FERC Form 714.

Monthly Generation, Load and Net Exports

Western Resources, Inc.

1995

(MWH)

Month	Generation (1)	Load (2)	Net Exports (3)=(1)-(2)
January	1,971,853	1,773,462	198,391
February	1,883,920	1,550,242	333,678
March	1,698,501	1,656,470	42,031
April	1,769,878	1,516,601	253,277
May	1,853,642	1,594,038	259,604
June	2,101,787	1,880,504	221,283
July	2,692,009	2,336,226	355,783
August	2,867,624	2,512,888	354,736
September	2,198,997	1,853,880	345,117
October	1,863,914	1,675,994	187,920
November	1,804,485	1,641,836	162,649
December	2,005,329	1,800,173	205,156

Sources: Kansas Power & Light's 1995 FERC Form 714.
Kansas Gas and Electric's 1995 FERC Form 714.

Generation, Load, and Net Exports at Monthly Peak

Western Resources, Inc.

1995

(MW)

Month	Generation (1)	Load (2)	Net Exports (3)=(1)-(2)
January	3,285	3,040	245
February	3,410	2,884	526
March	3,062	2,926	136
April	2,885	2,643	242
May	3,384	2,968	416
June	4,312	3,927	385
July	4,969	4,601	368
August	4,906	4,536	370
September	4,411	4,175	236
October	3,010	3,147	-137
November	2,963	2,942	21
December	3,270	3,091	179

Sources: Kansas Power & Light's 1995 FERC Form 714.
Kansas Gas and Electric's 1995 FERC Form 714.

Monthly Generation, Load and Net Exports

Combined Company

1995

(MWH)

Month	Generation (1)	Load (2)	Net Exports (3)=(1)-(2)
January	3,446,174	2,768,314	677,860
February	3,089,930	2,543,544	546,386
March	3,029,579	2,414,343	615,236
April	3,015,321	2,377,953	637,368
May	3,069,685	2,474,334	595,351
June	3,386,577	2,889,339	497,238
July	4,031,458	3,845,676	185,782
August	4,298,180	4,105,717	192,463
September	3,446,699	2,991,652	455,047
October	3,112,911	2,724,161	388,750
November	3,227,266	2,481,448	745,818
December	3,410,993	2,813,576	597,417

Sources: Kansas Power & Light's 1995 FERC Form 714.
Kansas Gas and Electric's 1995 FERC Form 714.
Kansas City Power & Light Company's 1995 FERC Form 714.

Generation, Load, and Net Exports at Monthly Peak

Combined Company

1995

(MW)

Month	Generation (1)	Load (2)	Net Exports (3)=(1)-(2)
January	5,716	4,906	810
February	5,483	4,662	821
March	5,251	4,723	528
April	4,739	4,269	470
May	5,344	4,898	446
June	6,548	6,567	-19
July	7,489	7,536	-47
August	7,153	7,501	-348
September	6,580	6,861	-281
October	4,984	5,074	-90
November	5,055	4,668	387
December	5,668	5,019	649

Sources: Kansas Power & Light's 1995 FERC Form 714.
Kansas Gas and Electric's 1995 FERC Form 714.
Kansas City Power & Light Company's 1995 FERC Form 714.

Monthly Generation, Load and Net Exports

Kansas City Power & Light Company

1996

(MWH)

Month	Generation (1)	Load (2)	Net Exports (3)=(1)-(2)
January	1,522,521	951,765	570,756
February	1,077,478	495,504	581,974
March	1,007,939	719,836	288,103
April	1,285,850	744,114	541,736
May	1,350,351	1,110,681	239,670
June	1,335,699	1,177,899	157,800
July	1,399,894	1,269,198	130,696
August	1,452,530	1,226,719	225,811
September	1,367,375	985,445	381,930
October	1,475,627	869,127	606,500
November	1,413,781	931,235	482,546
December	1,439,280	1,028,126	411,154

Source: Kansas City Power & Light Company's 1996 FERC Form 714.

Generation, Load, and Net Exports at Monthly Peak

Kansas City Power & Light Company

1996

(MW)

Month	Generation (1)	Load (2)	Net Exports (3)=(1)-(2)
January	1,830	1,984	-154
February	1,592	2,017	-425
March	1,537	1,872	-335
April	1,903	1,674	229
May	2,497	2,354	143
June	2,213	2,818	-605
July	2,591	3,015	-424
August	2,544	2,889	-345
September	2,177	2,564	-387
October	1,991	1,872	119
November	2,312	1,912	400
December	1,977	2,085	-108

Source: Kansas City Power & Light Company's 1996 FERC Form 714.

Monthly Generation, Load and Net Exports

Western Resources, Inc.

1996

(MWH)

Month	Generation (1)	Load (2)	Net Exports (3)=(1)-(2)
January	2,082,527	1,909,396	173,131
February	1,354,615	1,678,091	-323,476
March	1,613,065	1,738,365	-125,300
April	1,754,482	1,591,066	163,416
May	2,262,289	1,822,279	440,010
June	2,407,659	2,130,378	277,281
July	2,593,704	2,330,674	263,030
August	2,465,335	2,246,631	218,704
September	2,070,279	1,816,826	253,453
October	2,003,028	1,716,190	286,838
November	2,194,036	1,728,901	465,135
December	2,273,871	1,849,145	424,726

Sources: Kansas Power & Light's 1996 FERC Form 714.
Kansas Gas and Electric's 1996 FERC Form 714.

Generation, Load, and Net Exports at Monthly Peak

Western Resources, Inc.

1996

(MW)

Month	Generation (1)	Load (2)	Net Exports (3)=(1)-(2)
January	3,487	3,366	121
February	2,977	3,206	-229
March	2,880	3,071	-191
April	3,548	2,693	855
May	4,298	3,936	362
June	3,973	4,429	-456
July	4,890	4,616	274
August	4,639	4,443	196
September	4,578	4,056	522
October	3,000	2,983	17
November	3,567	3,031	536
December	3,761	3,287	474

Sources: Kansas Power & Light's 1996 FERC Form 714.
Kansas Gas and Electric's 1996 FERC Form 714.

Monthly Generation, Load and Net Exports
Combined Company
1996
(MWH)

Month	Generation (1)	Load (2)	Net Exports (3)=(1)-(2)
January	3,605,048	2,861,161	743,887
February	2,432,093	2,173,595	258,498
March	2,621,004	2,458,201	162,803
April	3,040,332	2,335,180	705,152
May	3,612,640	2,932,960	679,680
June	3,743,358	3,308,277	435,081
July	3,993,598	3,599,872	393,726
August	3,917,865	3,473,350	444,515
September	3,437,654	2,802,271	635,383
October	3,478,655	2,585,317	893,338
November	3,607,817	2,660,136	947,681
December	3,713,151	2,877,271	835,880

Sources: Kansas Power & Light's 1996 FERC Form 714.
Kansas Gas and Electric's 1996 FERC Form 714.
Kansas City Power & Light Company's 1996 FERC Form 714.

Generation, Load, and Net Exports at Monthly Peak

Combined Company

1996

(MW)

Month	Generation (1)	Load (2)	Net Exports (3)=(1)-(2)
January	5,317	5,350	-33
February	4,569	5,223	-654
March	4,417	4,943	-526
April	5,451	4,367	1,084
May	6,795	6,290	505
June	6,186	7,247	-1,061
July	7,481	7,631	-150
August	7,183	7,332	-149
September	6,755	6,620	135
October	4,991	4,855	136
November	5,879	4,943	936
December	5,738	5,372	366

Sources: Kansas Power & Light's 1996 FERC Form 714.
Kansas Gas and Electric's 1996 FERC Form 714.
Kansas City Power & Light Company's 1996 FERC Form 714.

Net Simultaneous Import Capability at the Time of Summer Peak

Scenario	SPP Methodology	Economic Dispatch	Maximize Import Capability
Pre-Merger			
Western Resources	887	581	1,887
KCPL	1,644	2,016	2,414
Post-Merger			
Combined Control Area	1,606*	704	1,606*

Notes: * For the combined control area, the same import limit is shown for both the SPP Methodology and the Maximize Import Capability cases. The limiting factor is a line in Union Electric's control area.

Source: Testimony of Richard Dixon.

Approximate Load Pocket Analysis
Summer Peak
SPP Transfer Methodology

Scenario	(1) Control Area Demand	(2) Control Area Generation	(3) Control area Generation Owned by Others	(4) Generation Owned by Control Area Operator	(5) Net Exports	(6) Simultaneous Transfer Capability	(7)=(5)+(6) Potential Loss	(8)=(7)/(4) Potential Loss as a Percentage of Generation
Pre Merger								
KCPL	3,128	3,034	873	2,161	-94	1,644	1,550	71.73%
Western	4,826	5,239	1,174	4,065	413	887	1,300	31.98%
Post Merger								
WR/KCPL	7,955	8,274	828	7,446	319	1,606	1,925	25.85%

Notes: Generation and loads are generator output levels and control area loads used in load flow studies. Net exports used in the load flow study include firm exports and imports only and do not include any projects of economy transactions.

For the combined control area, the same import limit is shown for both the SPP Methodology and the Maximize Import Capability cases. The limiting factor is a line in Union Electric's control area.

Sources: Testimony of Richard Dixon.
EIA Form 860.
FERC Form 714.

Approximate Load Pocket Analysis
Summer Peak
Economic Dispatch

Scenario	(1) Control Area Demand	(2) Control Area Generation	(3) Control area Generation Owned by Others	(4) Generation Owned by Control Area Operator	(5) Net Exports	(6) Simultaneous Transfer Capability	(7)=(5)+(6) Potential Loss	(8)=(7)/(4) Potential Loss as a Percentage of Generation
Pre Merger								
KCPL	3,128	3,034	873	2,161	-94	2,016	1,922	88.94%
Western	4,826	5,239	1,174	4,065	413	581	994	24.45%
Post Merger								
WR/KCPL	7,955	8,274	828	7,446	319	704	1,023	13.74%

Notes: Generation and loads are generator output levels and control area loads used in load flow studies. Net exports used in the load flow study include firm exports and imports only and do not include any projects of economy transactions.

For the combined control area, the same import limit is shown for both the SPP Methodology and the Maximize Import Capability cases. The limiting factor is a line in Union Electric's control area.

Sources: Testimony of Richard Dixon.
EIA Form 860.
FERC Form 714.

Approximate Load Pocket Analysis
Summer Peak
Maximum Import Capability

Scenario	(1) Control Area Demand	(2) Control Area Generation	(3) Control area Generation Owned by Others	(4) Generation Owned by Control Area Operator	(5) Net Exports	(6) Simultaneous Transfer Capability	(7)=(5)+(6) Potential Loss	(8)=(7)/(4) Potential Loss as a Percentage of Generation
Pre Merger								
KCPL	3,128	3,034	873	2,161	-94	2,414	2,320	107.36%
Western	4,826	5,239	1,174	4,065	413	1,887	2,300	56.58%
Post Merger								
WR/KCPL	7,955	8,274	828	7,446	319	1,606	1,925	25.85%

Notes: Generation and loads are generator output levels and control area loads used in load flow studies. Net exports used in the load flow study include firm exports and imports only and do not include any projects of economy transactions.

For the combined control area, the same import limit is shown for both the SPP Methodology and the Maximize Import Capability cases. The limiting factor is a line in Union Electric's control area.

Sources: Testimony of Richard Dixon.
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