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MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

REBUTTAL TESTIMONY

OF

MICHAEL S. PROCTOR

WESTERN RESOURCES, INC. AND KANSAS CITY POWER & LIGHT COMPANY

CASE NO. EM-97-515

Jefferson City, Missouri

April, 1999

REBUTTAL TESTIMONY

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MICHAEL S. PROCTOR

KANSAS CITY POWER & LIGHT COMPANY

AND WESTERN RESOURCES, INC.

CASE NO. EM-97-515

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Michael S. Proctor. My business address is 301 West High St., P.O. Box 360, Jefferson City, Mo. 65102-0360.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Missouri Public Service Commission (Commission) as Chief Regulatory Economist in the Electric Department.

Q. WHAT IS YOUR EDUCATION BACKGROUND AND WORK EXPERICENCE?

A. I have Bachelors and Masters of Arts Degrees in Economics from the University of Missouri at Columbia, and a Ph.D. degree in Economics from Texas A&M University. My previous work experience has been as an Assistant Professor of Economics at Purdue University and at the University of Missouri at Columbia. Since June 1, 1997 I have been on the Staff of the Commission and have presented testimony on various issues related to weather normalized energy usage and rate design for both electric and natural gas utilities. With respect to electric issues, I have worked in the areas of load forecasting, resource planning and transmission pricing. Last year, I served on the Commission's Task Force on Retail Competition as the Staff Vice Chair for the Market Structure and Market Power working group.

Q. WHAT ARE YOUR CURRENT DUTIES IN THE ELECTRIC DEPARTMENT AS CHIEF ECONOMIST?

A. In addition to advising the Staff of the Electric Department on various issues related to weather normalization of sales and rate design, my primary focus has been on the development and structure of regional transmission organizations (RTOs) for the purpose of increasing efficiency and reliability in the supply of electricity. Because of the restructuring of the electric industry toward the increased competitive supply of electricity, I have also focused my attention on the issue of market power within the electric industry.

Q. IN THIS INSTANT CASE, WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My rebuttal testimony will address the issue of the increase in market power that could occur if merger applicants, Kansas City Power & Light Company (KCPL) and Western Resources, Inc. (Western), were merged into a single corporate entity.

I. OVERVIEW AND KEY CONCEPTS

Q. WHAT ARE YOUR FINDINGS REGARDING THE POTENTIAL MARKET POWER OF THE MERGER APPLICANTS?

A. As a single corporate entity and without significant mitigation, the merger applicants would have substantial horizontal and vertical market power in both deregulated wholesale electricity markets and deregulated retail electricity markets.

I.A HORIZONTAL MARKET POWER

Q. WHAT IS THE DEFINITION OF HORIZONTAL MARKET POWER?

A. In the context of a market for a specific product (good or service), horizontal market power is defined as the ability of a provider to increase its profits simply by the manipulation of its offer price and/or output level for the product. Economists relate horizontal market power to the elasticity of the demand curve faced by individual providers within a market. At the one extreme, if the demand faced by the individual provider is perfectly elastic, this means that if the offer price is above the market price, the provider will lose all sales and therefore has no horizontal market power. At the other extreme, a monopolist, having no competitors, faces the entire demand curve for the market and is therefore free to set an offer price that maximizes its profits.

In essence, horizontal market power for a given entity, comes from the lack of sufficient competition from other entities able and willing to sell the same product at a lower, "competitive" price. If sufficient competitive alternatives are available, then when any single entity attempts to raise its offer price, the lower offer prices of competitors will cause that entity to lose significant market share (percentage of total market sales) and therefore profits.

Horizontal market power is directly correlated to the market shares of the competitors. At the extreme, a monopolist has one hundred percent of market share and complete horizontal market power. At the other extreme, in a perfectly competitive market, the market share of each competitor is extremely small, and any increase in offer price above the market clearing price (the price set where demand equals supply) results in the loss of all sales.

Near the monopoly extreme, the economic model that most directly connects horizontal market power to market shares is one in which the market is characterized by a dominant firm that faces competition only from a "competitive fringe." This competitive fringe is made up of much smaller firms, none of which is able to exert material influence on the market through its price-output decisions. In this model, the dominant firm establishes its preferred price as the going market price and allows the competitive fringe to sell all they wish at that price. Because the competitive fringe is small compared to the dominant firm, the dominant firm produces an amount sufficient to meet the remaining demand at the chosen market price.

Nearer to the perfectly competitive extreme, is a market characterized by several principal firms, where no single firm is powerful enough to impose its will upon the others consistently. These firms are of approximate equal size, and the number of firms gives a rough measure of the potential for price collusion - where the principal firms agree to an offer price and market shares, thus acting together as a dominant firm.

Q. WHAT IS THE FACTUAL BASIS FOR YOUR FINDING THAT THE PROPOSED MERGER WOULD RESULT IN A MERGED ENTITY HAVING SIGNIFICANT HORIZONTAL MARKET POWER?

A. The results of three distinct horizontal market power studies form the factual basis for my conclusion that the merged entity would have significant market power. First are the results of the destination market analysis, which the FERC requires all merger applicants to file. This study was filed in December 1998 at the FERC (Docket No. EC97-56-000) in response to the Director of Opinions and Corporate Applications' request for additional information. Second are the results of the initial market power study performed by the applicant, which I have subsequently corrected to apply to the Staff's determination of the relevant geographic market. The initial study was filed both at the FERC (Docket No. EC97-56-000) and with this Commission in December 1997. Third are the results of a retail market power study, which the Staff had performed under contract with LCG Consulting (LCG). LCG witness, Dr. Paresh Rupanagunta, has filed rebuttal testimony in this proceeding.

In the destination market analysis required by the FERC, the merger applicants witness, Dr. Robert M. Spann submitted testimony showing that the concentration thresholds set by the FERC were exceeded in the transmission dependent utility (TDU) destination markets located within Western's and KCPL's service territory.

If the initial market power study submitted by Dr. Spann is corrected to apply to the relevant geographic market area of the northern portion of the Southwest Power Pool (SPP), and if the transmission import limits into this relevant geographic market area are taken into account, the results are that as a single entity, the merger applicants will have a significant share of the market, resulting in concentration levels that exceed the thresholds set by the FERC.

In the retail market power analysis performed by LCG, the concentration thresholds set by the FERC for market concentration are exceeded in the relevant geographic market – the North region of the Southwest Power Pool (SPP). Most importantly, the LCG study shows that the merged entity could increase its offer prices above competitive levels and experience a significant increase in profits.

Q. WHAT ARE THE CONCENTRATION THRESHOLDS SET BY THE FERC?

A. In the FERC's Merger Policy Statement (Appendix A, p. 3) the concentration thresholds are based on levels and changes in the Herfindahl-Hirschmann Index (HHI) resulting from the merger. The HHI is the sum of the squares of the market shares expressed as percentage numbers. The market shares are for specific (relevant) products in specific (relevant) geographic markets. The thresholds for raising "significant competitive concerns" are: for HHI levels above 1,000 up to 1,800 and changes in the HHI from the merger greater than 100, or for HHI levels above 1,800 and changes in the HHI from the merger greater than 50.

Q. WHAT DO THE FERC CONCENTRATION THRESHOLDS IMPLY REGARDING THE LEVEL OF COMPETITION IN A GIVEN MARKET?

A. Assume the 1,000 HHI level is met in a market with ten competitors having equal market shares; i.e., each competitor has 10% market share, giving an HHI = $10*10^2 = 10*100 = 1{,}000$. This would correspond to the economic model in which there are several principle firms, no one of which is dominant.

If two of ten competitors were to merge, their market share would be 20%. When compared to a pre-merger situation where each individual competitor had 10% market share, the HHI would increase from 1,000 to 1,200 and would exceed the FERC safe harbor threshold; i.e., HHI = $(8*10^2 + 20^2) = (800 + 400) = 1{,}200$. The concern here would not be that there are too few firms implying the possibility of collusion, rather that with the merged firm having 20% market share, it could become a dominant firm.

In general, if the two merger applicants have equal or near equal pre-merger market shares, the FERC threshold of an increase in HHI by 100, limits merged market share to a maximum of 14.14%, and an increase of HHI by 50, limits merged market share to 10%.[1]

The 1,800 HHI level is met by 6 or more competitors having equal market shares, i.e., each competitor has 16⅔% market share, giving an HHI = $6*(16⅔)^2 = 6*(277.78) =$ 1,667. If two of six competitors having equal market shares were to merge, their market share would be 33⅓, and the HHI would increase from 1,667 to 2,222, an increase of 555; i.e., HHI = $[4*(16⅔)^2] + (33⅓)^2 = (1{,}111) + (1{,}111) = 2{,}222$. The concern here would be not only that with the merged entity, having one third of the market, it would become a dominant firm, but also with the number of firms being reduced from 6 to 5, the likelihood of collusion has increased.

There are a number of combinations of firms having unequal market shares that give HHI levels between 1,000 and 1,800, as well as corresponding numbers of combinations of mergers that would exceed the thresholds respecting increases in HHI. Because of this, it is important to look beyond the thresholds to determine whether the merger is likely to increase horizontal market power.

Q. HOW DO THE RESULTS OF THE THREE MARKET POWER STUDIES COMPARE TO THE FERC'S CONCENTRATION THRESHOLDS?

A. Dr. Spann's destination market analysis shows that in all but the lowest (off-peak) hours, Western has over 40% market share of economic capacity in the market for serving TDUs within its service territory, and KCPL has over 30% market share of

[1] The difference in HHI (post-merger – pre-merger) is $2x_1x_2$, where $x_1 = x_2 = x$ are the equal market shares of the merger applicants. Thus, the FERC concentration threshold limit of an increase of 100 in the HHI would correspond to $2x_1x_2 \geq 100$, or $x^2 \geq 50$, or $x \geq 50^{½} = 14.14$.

economic capacity in the market for serving TDUs within its service territory. Thus, with Western and KCPL being dominant firms in their respective service territories, the pre-merger HHIs exceed the 1,800 level, with the Western TDU markets in the range of 2,200 to 2,600 and the KCPL TDU markets in the range of 1,200 to 2,000. The merger increases HHIs in the range of from 250 to 450 points.

LCG's results for retail competition give the merged company market shares of 50%, split approximately 30% Western and 20% KCPL. Correcting Dr. Spann's original market power study for the relevant geographic market gives similar results. In my opinion, market shares at these levels are of significant concern because a firm with 50% market share can easily fit into the dominant firm model, facing competition only from a competitive fringe.

Q. WHAT IS ECONOMIC CAPACITY?

A. Economic capacity is the generation capacity that is able to compete at a given market price. Generally speaking, it would be any generation capacity having marginal costs at or below the specified market price. In a destination market power analysis, the cost of transmission required to deliver the electricity to the destination market is added to the marginal generation costs, with transmission losses also taken into account. In addition, the amount of economic capacity available to a destination market is limited by the transmission capability into the specified destination market.

Q. WHAT MEASURES DO YOU PROPOSE TO MITIGATE THE HORIZONTAL MARKET POWER OF THE MERGED ENTITY?

A. There are two possible horizontal market power mitigation measures that I consider being most effective. First is divestiture (sale) of enough generation assets to competitors to move from a dominant firm situation to one in which there are several (at least three) entities with approximately equal market shares. Second is requiring the merged entity to sell generation on a wholesale competitive bid basis to competitors in the retail electricity markets within the same relevant geographic market. Both of these mitigation options would be for a future date at which Missouri restructures retail electricity markets to allow for the competitive supply of electricity. [See section IV of this testimony for specific details.]

I.B VERTICAL MARKET POWER

Q. WHAT IS THE DEFINITION OF VERTICAL MARKET POWER?

A. Vertical market power is defined as the ability to limit the entry of competitors into the market. Vertical market power is exerted through the control of entry at any place along the production chain. For example, a firm entering early into the production of a good or service could limit entry of competitors by contracting to buy a major portion of the available supply of a critical and relatively scarce input; e.g., highly skilled labor. In electricity markets, the scarce resource would most likely be the availability of transmission capability for competitors to move energy from the generation source to the load destination. In many cases of vertical market power in the electric utility industry, the issue is not the ability or the direct costs of producing the product, rather it is the ability to get either the inputs or the product to a specific geographic location.

In the Federal Energy Regulatory Commission's (FERC's) Order No. 888, the issue being addressed was open access to transmission on a non-discriminatory basis in wholesale electricity markets. Order No. 888 was the FERC's initial attempt at eliminating vertical market power in wholesale electricity markets by requiring utilities to afford anyone wanting transmission service access to that service on the same basis that it is available to the utility owning the transmission facilities.

Q. WHAT IS THE FACTUAL BASIS FOR YOUR FINDING THAT THE PROPOSED MERGER WOULD RESULT IN THE MERGED ENTITY HAVING SIGNIFICANT VERTICAL MARKET POWER?

A. Vertical market power may exist in the transmission of electricity in at least three ways. First, because of pancaked transmission rates (adding together of transmission rates of individual electric utilities on a contract path) that are based on embedded costs, the amount of economic capacity available to compete within a destination market can be limited. Second, when the local utility maintains the ability to determine the amount of available transmission capability, access to the transmission system can be artificially limited. Third, when the requests for firm transmission service exceed the level of available transmission capability and the addition of new transmission capability is left to the utility, the utility can limit competition by slowing down or even shutting down the process of upgrading its transmission facilities.

While I am not aware of any specific evidence that either Western or KCPL have profited from the restrictions of: 1) pancaked transmission rates: 2) artificially limited available transmission capability; or 3) slowing their responses to requests for upgrades to transmission facilities, these "tools" of vertical market power are available at varying degrees.

Q. IN WHAT WAYS DOES THE MERGER INCREASE THE DEGREE OF OR POTENTIAL FOR VERTICAL MARKET POWER?

A. This proposed merger creates a situation in which a single entity would have significant control over transmission facilities in the North SPP region. Thus, the exertion of vertical market power by the merged entity through any of the above means will have a greater impact in restricting competition.

Q. WHAT MEASURES DO YOU PROPOSE TO MITIGATE THE POTENTIAL FOR VERTICAL MARKET POWER ABUSE BY THE MERGED ENTITY?

A. As a condition of approving the merger, the Commission should require a statement of intent from the merger applicants in which they agree to join an regional transmission organization in which pancaked transmission rates are eliminated, the available transmission capability is determined by an independent entity and transmission impact studies are administered by an independent entity. The independent entity can be an agent of the regional transmission organization if the governance of that organization does not allow transmission owners a block of votes that can veto on any of the above issues. In addition, if the regional transmission organization does not have in place policies that promote the timely upgrade or addition of new transmission facilities, the merged utility must agree to make timely upgrades or additions to the transmission system required by the regional transmission organization, subject to applicable regulatory approval. [See section IV of this testimony for specific details.]

I.C TESTIMONY STRUCTURE

Q. WHAT IS THE STRUCTURE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony is divided into two main sections. The first section deals with the evidence regarding the levels and changes in horizontal market power from the merger. The second section deals with vertical market power analysis and issues. Within the horizontal market power section, issues related to the following major topic areas are presented:

II.A DESTINATION MARKET POWER ANALYSIS

II.B RELEVANT GEOGRAPHIC MARKETS

II.C RETAIL ELECRTIC COMPETITION

Within the vertical market power section, issues related to the following major topic areas are presented:

III.A TRANSMISSION COSTS

III.B TRANSMISSION AVAILABILITY

III.C TRANSMISSION PLANNING

In addition, there is a final section wherein the conditions that I recommend be included for approval of the merger are spelled out.

IV. REQUIRED MARKET POWER MITIGATION MEASURES

In essence, the remainder of my rebuttal testimony presents the specifics of the market power analysis and the issues that the Staff has with the filed position of the merger applicants.

II. HORIZONTAL MARKET POWER ISSUES

II.A DESTINATION MARKET POWER ANALYSIS

Q. WHAT IS A DESTINATION MARKET?

A. For purposes of horizontal market power analysis, a destination market is any utility service territory that might be adversely affected by the increase in horizontal market power resulting from the merger.

Q. IN DR. SPANN'S ANALYSIS, WHICH DESTINATION MARKETS WERE CONSIDERED?

A. In addition to the service territories of the merger applicants, Dr. Spann included the service territories of all of the investor-owned utilities in Missouri (Ameren, Missouri Public Service, Empire District Electric and St. Joseph Light & Power); Associated Electric Cooperative, Inc. in Missouri; City Power & Light in Independence, Missouri; Board of Public Utilities in Kansas City, Kansas; UtiliCorp's WestPlains Energy in Kansas; Midwest Energy, Inc. in Kansas; MidAmerican Energy Company in Iowa; Public Power Companies in Nebraska (Lincoln Electric System, Nebraska Public Power District and Omaha Public Power District); and the two major investor-owned utilities in Oklahoma (Central and South West Corporation - SPP and Oklahoma Gas & Electric Company). While this list does not include all of the destination markets that might be affected by the merger, Dr. Spann has included the largest utilities nearest to KCPL and Western. He has also included a few smaller utilities (Kansas City, Kansas Board of Public Utilities, Midwest Energy, WestPlains and City Power & Light – Independence, Mo.) that are within the transmission control areas of the merger applicants.

Q. WHAT IS THE PURPOSE OF A DESTINATION MARKET POWER ANALYSIS?

A. The FERC requires merger applicants to perform destination market power analysis as a way of screening out mergers respecting which the FERC can be assured that there are no competitive concerns. If a proposed merger passes the destination market screen, then it can be processed more quickly. Failure to pass the destination market power analysis only raises concerns regarding the increase in market power from the merger. If merger applicants are willing in their filings to propose mitigation measures that cause the HHIs to fall within the thresholds set by the FERC, then the hearings at the FERC tend to focus on proper mitigation measures and levels. Thus, while the thresholds are not taken as "proof" of too much horizontal power, in many instances the thresholds have become the standard to be met by the merger applicants.

Q. WHAT IS THE METHODOLOGY USED IN PERFORMING A DESTINATION MARKET POWER ANALYSIS?

A. The analysis is done for various delivered prices with the objective of determining the maximum amount of generation capacity that is able to compete in the destination market at those delivered prices. The words, "delivered price," imply that transmission costs are to be added to generation costs for determining the price in the destination market. Generation capacity that can produce electricity which can be delivered at a marginal cost that is not higher than 105% of the delivered price is a potential candidate for being competitive. The FERC uses the term "economic capacity" for all generation capacity the marginal cost of which is at or below 105% of the delivered price. What restricts the amount of economic capacity from actually being competitive in the destination market is the availability of transmission.

Q. WHAT DELIVERED PRICES DID DR. SPANN USE IN HIS DESTINATION MARKET POWER ANALYSIS?

A. For each destination market, Dr. Spann divided the year into nine sub-periods, starting with the highest 100 hours and going to the next 250, 400, 600, 800, 1,000, 1,600, 1,500 and 2,410 hours. For each destination market and for each of these groupings of hours Dr. Spann determined the 1997 average system lamdas (marginal cost), which were then used as the delivered prices. Over all destination markets, these delivered prices range from a high of $57.03/MWh to a low of $7.79/MWh. In each destination market, the delivered prices are typically the highest for the highest 100 hours and fall as the load decreases in magnitude. The graph and tables in Schedule 1 show the delivered prices for KCPL and Western.

Q. HOW DOES TRANSMISSION AVAILABILITY LIMIT THE AMOUNT OF ECONOMIC CAPACITY THAT IS ACTUALLY CONSIDERED TO BE COMPETITIVE IN THE DESTINATION MARKET?

A. For destination markets outside of the Southwest Power Pool (SPP) and the Mid-Continent Area Power Pool (MAPP), a contract path form of transmission availability is used to determine the amount of economic capacity that can reach the destination market from the various sources. For destination markets within SPP and MAPP a flow-based approach is used in which the energy flows are distributed across all possible transmission connections between the generation source and the load destination. The transmission paths are characterized as transmission interfaces connecting the various control areas. Transfer capabilities are limited by available transmission capability (ATC) to measure transfer capability on a specific contract path, and first contingency incremental transfer capability (FCITC) to measure non-simultaneous transfer capability between NERC regions. Where the flow-based approach is used within SPP and MAPP, flowgate limits restrict the transfers of electricity and provide a measure of the simultaneous transfer limit on flows that can be imported or exported to each control area in SPP and MAPP. Where contract paths apply, thermal limits also restrict the amount of electricity that can be transferred between control areas. These thermal limits were applied between SPP control areas and non-SPP control areas that are directly connected to SPP control areas.

Q. HOW ARE THE SIMULTANEOUS TRANSMISSION LIMITS ALLOCATED AMONG POTENTIAL SUPPLIERS?

A. My understanding is that Dr. Spann's used a linear programming model with the objective of maximizing the amount of economic capacity that can reach a destination market, subject to the transmission constraints. Simultaneous transmission limits were allocated among potential suppliers on a pro rata basis. It appears that these pro-rata shares are based on the total amount of economic capacity that each potential supplier has available at the specified level for the delivered price.

Q. WHAT WERE THE RESULTS OF DR. SPANN'S DESTINATION MARKET POWER ANALYSIS?

A. I have included Dr. Spann's results on Schedules 2.1 through 2.3 for all but three of the destination markets. The three destination markets excluded in Schedules 2.1 through 2.3 are City Power & Light, Independence, Mo., Midwest Energy and

WestPlains Energy (UtiliCorp). In these three destination markets the FERC thresholds for HHI concentration levels were clearly met, and there were no competitive concerns. This also appears to be true for Empire District Electric Company, but I included the results because it is an investor-owned utility regulated by this Commission.

Q. WHAT DO THE RESULTS OF DR. SPANN'S DESTINATION MARKET POWER ANALYSIS INDICATE ABOUT THE IMPACT OF THE MERGER ON HORIZONTAL MARKET POWER?

A. The results on Schedules 2.1 through 2.3 vary by delivered price, but consistently over all delivered prices, the Western and KCPL destination markets appear as significantly failing the FERC's thresholds for concentration. In every case, these destination markets are dominated by the incumbent provider having significant market share. For example, Western has around 50% market share in its control area for all hours except in the lowest off-peak hours, where its market share is still at the 30% level. KCPL has around 40% market share in its control area, similarly dropping to a 20% level in the off-peak hours. These market shares indicate incumbent market power and would not necessarily be affected by the merger. Based on the pro rata allocation of transmission limits, the merger partner's share in the other partner's destination market is reported to be in the 4% range. In my opinion, the allocation of simultaneous transmission limits on a pro rata basis can understate the impact on concentration of the merger on market shares within the destination markets of the merger applicants. Even so, the results of combining the market shares of the incumbent with the market shares of its merger partner, results in increasing the HHIs by significant levels in the range of 200 to over 400 points.

Of the other Missouri utilities where horizontal market power appears to be a problem with HHI levels above 1,000, it is appears that the significant contribution to concentration in these markets is also from incumbent market shares. Ameren is the strongest example with HHI's in excess of 3,000 and market shares of approximately 60%. In most cases, the merger applicants have small enough market shares in these other markets that the merger has little impact. Two exceptions occur with the Associated Electric Cooperative and St. Joseph Light & Power destination markets. The HHIs for Associated Electric Cooperative are in the range of from 1,000 to 1,500, depending on the hours (delivered prices) involved. In all but the two highest peak hour sets (highest 100 and next 250 hours), the merger results in increases in the HHI that do not meet the FERC thresholds. The HHIs for St. Joseph Light & Power are in a somewhat narrower range of from 1,000 to 1,200. The merger does not cause the change in the HHI's to exceed the 100 threshold limit, although there are several changes above 80 points.

For the Oklahoma markets, both Central and Southwest (CSW) and Oklahoma Gas and Electric (OGE) destination markets have HHIs in excess of 2,000, with CSW's HHIs falling into the 1,000 to 2,000 range in the lower intermediate and off-peak hours. CSW has markets shares ranging from 23% in the lowest off-peak hours to 52% in the highest on-peak hours, and OGE's market shares range from 47% in the off-peak hours to 67% in the highest on-peak hours. However, in both cases, the merger never results in increases in concentrations high enough to violate the FERC's threshold limits.

For the Iowa area, MidAmerican Energy has HHIs ranging from 1,000 to 1,500 and market shares ranging from 13% in the off-peak hours to 34% in the on-peak hours.

While the proposed merger does give the merger applicants over 10% combined market share, the HHI levels do not increase by 100 points or more.

For the Nebraska markets, Omaha Public Power District (OPPD) has HHIs in the 2,000 and above range. The other two destination markets, Lincoln Electric System (LES) and Nebraska Public Power District (NPPD) have HHIs that are for most cases below the 1,000 level. Because of the high concentration levels in the OPPD destination market, there is one instance where the increase in HHIs exceeds the 50 point limit of the FERC thresholds. It is also interesting to note that in the other two Nebraska destination markets, the merger has a larger impact with merger applicants' market share getting as large as 15%. But because the incumbent shares are of approximately that same magnitude, there appear to be no competitive concerns raised by the proposed merger.

Q. WHAT IS THE OVERALL PICTURE OF COMPETITION THAT THESE DESTINATION MARKET POWER ANALYSES GIVE?

A. The picture is one where the larger utilities have significant market power within their own service territories. Market shares for incumbents are highest during the peak hours, ranging from 30% to 60%, and lowest during the off-peak hours, ranging in the teens and twenty percent levels (with the exception of OGE, which maintains a 57% off-peak market share and Ameren, which maintains a 56% off-peak market share). The merger applicants' post-merger market shares would range from 48% on-peak to 30% off-peak in the Western destination market and from 47% on-peak to 18% off-peak in the KCPL destination market. The picture is one of incumbent utilities being dominant in their existing territories, with a merger of KCPL and Western resulting in expanding this dominance.

Q. DOES THE DESTINATION MARKET POWER ANALYSIS NEED TO BE CONFIRMED BY OTHER FORMS OF MARKET POWER ANALYSIS?

A. Yes, it does. If the destination market power analysis is indicating that there is a potential problem with shrinking competition, the next step is to check out the situation by determining the level of competition in what is called the relevant geographic market.

II.B RELEVANT GEOGRAPHIC MARKETS

Q. WHAT IS THE CONCEPT OF A RELEVANT GEOGRAPHIC MARKET?

A. In general, a relevant geographic market is an area in which a group of principal electricity competitors are located and into which electricity competition from principal competitors in adjacent electricity markets is sufficiently restricted by transmission constraints and/or transmission costs that the full economic capacity of these competitors should not be included in the determination of market shares. Of course, this also implies that the exports into other markets from the principal electricity competitors within a relevant geographic market is also sufficiently restricted that their ability to compete is not at their full economic capacity level in those export markets. The generation located within the relevant geographic market is included at its full economic capacity level.

If the merger applicants are adjacent to one another, then the relevant geographic market is focused on the service territories of the merger applicants, with competitors being added from surrounding utilities to the extent that the transmission constraints and costs do not prohibit those utilities from being principal competitors in the market involving the generation of the merger applicants.

Q. HOW DO FIRST TIER UTILITIES FIT INTO THE DETERMINATION OF A RELEVANT GEOGRAPHIC MARKET?

A. The first tier of a utility includes all of the utilities that are directly connected with it. While some of these utilities may be principal competitors in terms of their size relative to the utility at the center, the transmission interface connecting a first tier utility to the utility at the center may be so constrained that its ability to compete renders its competition to be fairly insignificant. The first tier utility whose capacity is highly restricted by transmission into the service territory of the utility at the center, should be viewed as an importer into the relevant geographic market rather than as a part of the relevant geographic market. In essence, the economic capacity of that utility is included, but on a restricted basis, much like what occurs in the destination market analysis. This same type of condition would apply to second and upper tier utilities, with transmission costs becoming an increasingly important factor in restricting competition.

Even if the transmission interfaces from several utilities are not highly constrained in the sense of rendering each individual utility as belonging to the competitive fringe, it is possible that the simultaneous transfer capability is sufficiently restrictive that several first tier utilities will be severely limited in their ability to compete. In this case, the group of first tier utilities are excluded from the relevant geographic market, although their economic capacity should be included in imports.

Q. HOW DOES A RELEVANT GEOGRAPHIC MARKET DIFFER FROM A DESTINATION MARKET?

A. A destination market is centered at the service territory of a specific utility or load. A relevant geographic market expands the area to include multiple service territories. In a destination market power study, all transmission constraints into the destination market are important to the determination of market shares. For a relevant geographic market, transmission constraints within the relevant geographic market can determine the levels at which generation at various locations operate, but there is no attempt to assign that generation to a specific destination market within the relevant geographic market.

Q. DID YOU WORK WITH LCG IN DETERMINING THE RELEVANT GEOGRAPHIC MARKET FOR THIS PROPOSED MERGER?

A. Yes, I did. We determined that given the structure of LCG's model, the best approach to determining the relevant geographic market for this proposed merger was to compare the market clearing prices at various nodes throughout the transmission network. In this context, a node is a location in the transmission network for generation and/or load. The LCG model determines the least-cost dispatch of generation throughout the network, subject to the transmission constraints (see the rebuttal testimony of Paresh Rupanagunta). This dispatch is done on an hourly basis for an entire year, much like the production cost models which the Staff runs for rate cases and complaint cases. The LCG model then determines the market-clearing price at each node in the network. Absent transmission losses and transmission constraints, the market-clearing prices would be identical at every load node throughout the network. To the extent that prices differ among nodes, indicates that there are different geographic markets for generation resulting from restrictions in power flows brought about by constraints on the transmission system.

Q. WHAT WAS LCG'S DETERMINATION OF THE RELEVANT GEOGRAPHIC MARKET FOR KCPL AND WESTERN?

A. LCG determined that the relevant geographic market for KCPL and Western includes the northern region of SPP along with Associated Electric Cooperative (AEC), which was included in the northern region of SPP prior to leaving SPP and joining the Southeast Electric Reliability Council (SERC), and the Southwestern Power Administration (SPA), which provides a portion of its hydroelectric generation to AEC under federal contracts (SPA is a federal agency). A list of those utilities included in the relevant geographic market for KCPL and Western includes:

1. Associated Electric Cooperative
2. Empire Distric Electric
3. City Power & Light, Independence, MO
4. Board of Public Utilities, Kansas City, KS
5. Missouri Public Service
6. Municipalities and Cooperatives in Kansas
7. Municipalities in Missouri
8. City Utilities, Springfield, MO
9. St. Joseph Light & Power
10. Southwest Power Administration
11. West Plains Energy
12. Kansas City Power & Light
13. Western Resources

In addition to these 12 competitors (Missouri Public Service and WestPlains Energy are both owned by UtiliCorp), competitive alternatives in this relevant geographic market would also include imports from the Mid-America Interconnected Network (MAIN) and from the other utilities in SPP.

Q. DOES THE RELEVANT GEOGRAPHIC MARKET CHANGE OVER TIME?

A. Yes, it does. The relevant geographic market specified for this market power study is for a snapshot in time. While the relevant geographic market set out above is based on annual averages of nodel-spot prices, it is possible that at specific hours during the year nodes outside the specified relevant geographic market have market-clearing prices very close to nodes within the region. For purposes of this market-power study, I believe that having a relevant geographic market that applies throughout the year is sufficient.

Q. HOW WOULD YOU DESCRIBE THE TYPE OF COMPETITION FOR GENERATION THAT WILL LIKELY TAKE PLACE WITHIN THIS RELEVANT GEOGRAPHIC MARKET?

A. Of the 12 competitors, there are three principal suppliers, AEC, KCPL and Western. At the next level, while the SPA is a significant competitor during peak periods, the remaining 8 competitors make up a competitive fringe, along with imports from outside the region.

Q. WHAT IS THE BASIS FOR YOUR DESCRIPTION OF THE COMPETITION FOR GENERATION IN THE RELEVANT GEOGRAPHIC MARKET?

A. First, this description is consistent with the information in LCG's report on market power. Second, I derived a similar view of the competitive landscape when I applied the definition of this relevant geographic market to the original market power study submitted by Dr. Spann. In order to apply this definition, I used the first contingency maximum transfer capabilities (FCMTC) reported by the SPP for various regions within the SPP, including imports from MAIN, MAPP and the Tennessee Valley Authority (TVA). These FCMTC constraints are shown on Schedule 3 attached to my rebuttal testimony.

There are two things to note about these constraints. First, this is the latest SPP study available at the time of this filing. This study was performed prior to the AEC and Entergy Corporation leaving SPP and joining SERC. Thus, AEC is treated by SPP as being in the North SPP Region and Entergy is treated as being in the ARLAMS (Arkansas, Louisiana, Mississippi) SPP Region. Second, FCMTC limits are not simultaneous import restrictions, and therefore the results will likely allow more imports into the relevant geographic market than could occur on a simultaneous basis. The results of applying these FCMTC constraints on Dr. Spann's market power study are shown in Schedules 4.1 through 4.4.

Q. WHAT CASES ARE SHOWN IN SCHEDULES 4.1 THROUGH 4.4?

A. Dr. Spann submitted several scenarios, including the four that appear in these schedules. In each of these four cases, transmission prices are assumed to be zero. In each of these four cases, economic capacity is determined by the specified price levels (14 mills, 20 mills, 25 mills and 35 mills). As the specified price level increases, the amount of generation that each owner is able to supply on an economic basis (with costs at or below the specified price) increases.

Q. HOW DO SCHEDULES 4.1 THROUGH 4.4 DIFFER FROM THOSE OF DR. SPANN?

A. I have divided the owners of generation into regions that correspond to the SPP Regions, as well as sources comprising regions outside of SPP that can import into the SPP Regions. These regions include: 1) North SPP Region; 2) West Central SPP Region; 3) South SPP Region, which includes ARLAMS plus SOLA (Southern Louisiana); 4) MAIN; 5) TVA; and 6) MAPP. I applied the FCMTC transmission import limits into the North SPP Region to the generation reported by Dr. Spann in each of the other five regions on a pro rata basis.

Q. HOW DO SCHEDULES 4.1 THROUGH 4.4 DIFFER FROM THE RESULTS OF LCG?

A. Because the regions are slightly different (the North SPP Region does not include SPA, while LCG includes SPA in the relevant geographic market), Schedules 4.1 through 4.4 are not directly comparable to the LCG results, however they are very close and there are many similarities. First, AEC, KCPL and Western are the principal suppliers of generation in the North SPP region, and this is also true for the LCG study. In my analysis, Entergy would be a principal supplier, even with the import restrictions from Entergy into the North SPP region, but this is not the case for the LCG study. Also in my analysis, TVA, while not a principal supplier in the North SPP region, shows up as a significant provider, comparable to SPA's on-peak role in the LCG analysis. All other suppliers would more or less fall into the category of the competitive fringe.

Q. WHAT ARE THE CONCENTRATION EFFECTS OF APPLYING IMPORT RESTRICTIONS INTO THE NORTH SPP REGION?

A. At all four pricing levels, the pre-merger HHIs are around 1,000, and the post-merger HHIs show increases of from 486 points up to 579 points, resulting in post-merger HHIs in a range from above 1,400 to just over 1,700. According to the FERC thresholds, this merger posses competitive concerns within the relevant geographic market. Moreover, at all four levels of economic capacity shown in Schedules 4.1 through 4.4, a market with four principal competitors (KCPL, Western, AEC and Entergy) is reduced to one having one principal competitor (the merged company) and three significant competitors (AEC, Entergy and TVA).

Q. HOW DOES THE RELEVANT GEOGRAPHIC MARKET DIFFER FROM WHAT DR. SPANN HAS PROPOSED?

A. Dr. Spann would include all of the economic capacity shown in the first numbered column on these Schedules as being in the relevant geographic market, thereby ignoring any transmission constraints among the various sub-regions. If this approach is taken, then TVA becomes the dominant provider, with approximately ten other utilities playing the role of significant suppliers, and all remaining utilities being part of the competitive fringe. The total generation supply in Dr. Spann's expanded view of the relevant geographic market is from two to four times larger than the generation supply available to the North SPP Region.

Q. HAVE YOU REVIEWED DR. SPANN'S REASONS FOR SPONSORING SUCH A LARGE RELEVANT GEOGRAPHIC MARKET?

A. Yes, I have. In Dr. Spann's original direct testimony filed at the FERC, he presented arguments for a large region being the relevant geographic market. Dr. Spann's approach to determining the relevant geographic market focuses on determining the competitors to the merging firms. In order to determine these competitors, Dr. Spann examined: 1) the geographic area in which the merger applicants currently sell wholesale power; 2) competitors that sell wholesale power in the same area; and 3) the direction of power flows in the area where the merger applicants operate.

Q. WHAT WERE THE RESULTS OF DR. SPANN'S EXAMINATION OF THE MERGER APPLICANTS' CURRENT SELLING AREA AND COMPETITORS THAT COMPETE IN THAT AREA?

A. For non-firm and short-term (less than one year) firm sales, Dr. Spann found that for KCPL, the two dominant buyers outside of the North SPP Region are Ameren and the Arkansas Rural Electric Cooperative. He found that for Western, the two dominant buyers outside the North SPP Region are OGE and CSW-SPP. He also found that for both Western and KCPL, the role of power marketers was becoming more and more significant. In addition, Dr. Spann found buyers throughout the SPP, MAIN, MAPP and SERC regions, but I would not characterize any of these buyers as "dominant".

With respect to competitors in this expanded region, it appears that Dr. Spann's primary conclusion is that while KCPL and Western may have some sales into the MAPP region, the utilities in that region are primarily in competition for sales to the south of KCPL and Western. However, the degree of their competition is limited by transmission availability.

Q. DO YOU BELIEVE THAT AN ANALYSIS OF THE MERGER APPLICANT'S HISTORICAL PATTERN OF WHOLESALE SALES IS SUFFICIENT TO DETERMINE THEIR RELEVANT GEOGRAPHIC MARKET?

A. No. For purposes of considering the relevant geographic market for retail competition, an analysis of historical patterns of *wholesale sales* is not sufficient in order to make a determination of the relevant geographic market for a proposed merger. While this information might be relevant for wholesale markets as they exist today, it does not take into account the impact that going to retail competition can have on power markets. In addition, the fact that power marketers are playing a more important role in wholesale power transactions is important with respect to having a vibrant wholesale market, but does not directly bear on the question of the relevant geographic market for retail competition. It was because of the potential change from existing patterns of competition that the Staff sought a consultant to develop a model of retail competition and do an analysis of power markets based on the results of the model.

Q. WHAT WERE DR. SPANN'S CONCLUSIONS REGARDING HIS ANALYSIS OF POWER FLOWS IN THE REGION?

A. Based on his analysis of power flows, Dr. Spann concludes: "The power flow data indicate that the wholesale electric power market activity in this region tends to focus toward the Entergy system. Entergy tends to be a regional 'hub.'" It is not clear from Dr. Spann's testimony as to whether this is the primary reason that he has used an expanded region for the relevant geographic market, but my reading of his testimony along with his specification of the relevant geographic market leads me to believe that his view of the wholesale power markets is one in which Entergy is the center/hub. (For example, in one of the scenarios which Dr. Spann presents, he includes transmission costs from the utilities shown on Schedules 4.1 – 4.4 into the Entergy system in his determination of relevant economic capacity.)

Q. DO YOU AGREE WITH DR. SPANN'S CONCLUSION THAT ENTERGY IS A MARKET HUB?

A. To some degree, I agree that existing power flows are predominantly from north to south throughout the Midwest region, and in particular for the western end of the Midwest region that includes the SPP and MAPP. In part, the northern utilities have coal-fired generation that is cheaper because of lower transportation costs for coal and southern utilities have gas-fired generation that is cheaper because of lower transportation costs for natural gas. There is also load diversity between north and south, with the south being dominantly summer peaking and the north having relatively higher winter peak loads when compared to summer peak loads. Thus, sales of less expensive generation in the north not needed to meet native load would tend to go to the south.

Entergy is one of the largest systems in the mid-south area, and has a very active power marketing function. The reason that Entergy may appear to be a hub is because of its aggressive power marketing function rather than because of the location and type of its generation for serving native load customers. Because power can be bought in the north and then resold in the north by a power marketer in the south, it is not clear that wholesale prices reported at the Entergy "hub" are truly locational prices. Again, it is important to model the markets in the context of full retail competition in order to correctly identify locational prices. When this is done, differences in locational prices across areas can be used to identify relevant geographic markets.

Finally, what concerns me most about treating Entergy as a market hub is the restrictions on transmission into and out of the Entergy control area (see Schedule 3 for import and export limits into the ARLAMS region). If the transmission system is tight in a particular area, these are exactly the types of transmission constraints that should be used to delineate relevant geographic markets.

Q. DID DR. SPANN INCLUDE EITHER EXPORT OR IMPORT CONSTRAINTS IN HIS MARKET POWER ANALYSIS?

A. He did not. I understand why transmission limits within the relevant geographic market were excluded from Dr. Spann's analysis of market power, but his whole analysis leads to a view of the market that is difficult to interpret.

Had Dr. Spann performed an analysis on a market centered in the Entergy control area that included limits on imports into Entergy, such an analysis would be either a destination market analysis for Entergy, or an analysis of the relevant geographic market for Entergy. Because of the restricted level of import limits into Entergy (in Schedule 3, only 550 megawatts from the North SPP Region), one would not expect the proposed merger to have much of an impact on Entergy as a destination market. The difficulty in interpreting Dr. Spann's view of the relevant geographic market is as follows:

> *If because of import limits, the proposed merger has little impact on Entergy as a destination market, how can Entergy be included as the market hub for a relevant geographic market that includes the generation of the merger applicants?*

If transmission constraints within a region result in the merger applicants being only a competitive fringe in other destination markets located within that region, the specification of the relevant geographic market should exclude those destination markets as irrelevant. This does not mean that the economic capacity located in these areas is totally excluded from the relevant geographic market. However, that economic capacity should only be taken into account in terms of availability of transmission into the relevant geographic market.

Q. WHAT IS THE ROLE OF THE MERGER APPLICANTS IN THE ENTERGY DESTINATION MARKET?

A. Dr. Spann did not perform a market power analysis for Entergy as a destination market. However, based on the information in Dr. Spann's original market power analysis, in which he treated Entergy as a market hub, a measure of the merger applicants' potential role in a geographic market that is likely to be the relevant geographic market for Entergy can be developed. Schedules 5.1 through 5.4 focus on the South SPP Region as a relevant geographic market. The difference between Schedules 5.1 through 5.4 and Schedules 4.1 through 4.4 is that the FCMTC transmission limits are applied to imports into the South SPP Region. Imports from the North and West Central Regions of SPP, as well as imports from MAIN, are derived from Schedule 3. In order to complete Dr. Spann's view of the Entergy market, his calculation of the economic capacity from the Southern Company has been added, and the FCMTC constraints from the Southern Company into the South SPP region (from the North American Electric Reliability Council's (NERC's) 1998 Summer Assessment) limits imports into Entergy from Southern to 1,501 MW. I also used the NERC's 1998 report for FCMTC transfer limits of 2,868 MW from TVA into Entergy. These calculations show that even on a post-merger basis, the merger applicants will have less than 3% market share in the Entergy destination market.

Q. SHOULD DR. SPANN HAVE FOLLOWED THE DEPARTMENT OF JUSTICE (DOJ) GUIDELINES FOR DETERMINING THE RELEVANT GEOGRAPHIC MARKET?

A. The DOJ Guidelines for determining the relevant geographic market, or some test similar to those Guidelines should have been followed. The DOJ Guidelines require the application of the "hypothetical monopolist" test. [U.S. Department of Justice and Federal Trade Commission, Horizontal Merger Guidelines, 57 Fed. Reg. 41,552 (1992)] The application of that test would require treating all of the generation located within the proposed relevant geographic market as a monopoly. If increasing the offer price of this generation results in an increase in monopolist profits, then the geographic region is a candidate for the relevant geographic market. The "hypothetical monopolist" test states that the relevant geographic market for a proposed merger is the smallest geographic region for which a profitable increase in offer price by the hypothetical monopolist results in a market price increase of five percent or greater. Dr. Spann should have demonstrated that the hypothetical monopolist test failed for geographic markets smaller than his proposed relevant geographic market.

Q. ONCE THE RELEVANT GEOGRAPHIC MARKET IS DEFINED, HOW SHOULD ECONOMIC CAPACITY FROM OUTSIDE THIS REGION BE TAKEN INTO ACCOUNT?

A. In most instances, economic capacity from outside the relevant geographic market is involved in the specified market at a competitive fringe level. LCG took into account economic capacity from outside the relevant geographic market by determining the imports into that market area. I believe that this is the proper approach to treating the competitive impacts of economic capacity from outside the relevant geographic market. This approach does not include all of the economic capacity of competitors located outside the relevant geographic market. Instead, it limits the relevant economic capacity to what the model indicates are flows into the relevant geographic market from the surrounding regions. Of course, these flows are restricted by transmission constraints.

This approach indicates that while, at times there may be sufficient transmission capability for Entergy to export additional electricity into the North SPP Region, Entergy's economic capacity is actually flowing to other regions in the mid-south. This approach to measuring imports based on power flows into a region gives an analysis of the power flows that are most likely to occur in a highly competitive situation. In this analysis, Entergy is not a principal competitor in the North SPP Region.

Q. WHAT IS YOUR CONCLUSION REGARDING THE RELEVANT GEOGRAPHIC MARKET FOR THE PROPOSED MERGER?

A. The relevant geographic market is the North SPP Region, including AEC. There are three principal competitors within that region, AEC, KCPL and Western. While Entergy, Southwestern Power Administration, Central and South West - SPP and Oklahoma Gas and Electric will likely play some role in this market, their participation will be restricted by transmission availability.

Q. WHAT IS YOUR CONCLUSION REGARDING THE HORIZONTAL MARKET POWER OF THE MERGER APPLICANTS IN THE MERGED COMPANIES' RELEVANT GEOGRAPHIC MARKET?

A. With only three principal competitors within the relevant geographic market, a merger that reduces this number to only two principal competitors will have a significant negative impact on the level of competition within that market. The Commission should not approve this merger without having the assurance that it can mitigate the market power effects of the merger at the time of retail electric competition in Missouri.

II.C RETAIL ELECTRIC COMPETITION

Q. WHAT DO YOU MEAN BY RETAIL ELECTRIC COMPETITION?

A. In Missouri, retail electric competition will likely mean that retail customers who are currently being supplied electricity by a single utility at regulated rates will be supplied electricity by several retail electric providers (REPs) at competitively determined prices. These REPs will be responsible for arranging for both the generation and transmission of the electricity to the local distribution utilities (LDUs) that provide consumers with local wires services.

Q. WHAT ARE THE IMPLICATIONS OF RETAIL ELECTRIC COMPETITION ON WHOLESALE MARKETS FOR ELECTRICITY?

A. Currently, utilities have an obligation to serve retail electric customers located within their service territories. Thus, wholesale transactions primarily focus on the exchange of energy available from generation capacity not needed to serve retail load. These interchange transactions involve only a limited amount of the total electricity generated. In addition, because there was overall excess generation capacity in the Midwest region, wholesale transactions occurred in which capacity was exchanged for the purpose of providing generation reliability in serving retail electric customers. As this excess capacity diminished, wholesale competition in building new generation capacity to sell to utilities that are serving retail customers has occurred.

With retail competition, all existing generating capacity will be for sale. I would expect this capacity market to be one in which generation owners make sales to REPs on a year ahead basis. I would also expect wholesale contracts in which the capacity and energy from a generation owner are bundled together in many different ways. A standard approach to having two distinct electricity products in the wholesale market will be for wholesale contracts to include:

1) a capacity charge that is paid for having a specified level of megawatts of generation capacity available for use (reservation charge); and
2) an energy charge that is paid for the megawatt-hours of electricity used/taken by the REP under the contract (usage charge).

Q. ARE YOU FAMILIAR WITH WHAT HAS COME TO BE CALLED THE "POOLCO MODEL" OF RETAIL COMPETITION?

A. I am. In the Poolco model of retail competition, a central pool is formed with the purpose of purchasing energy to supply the electricity requirements of end-use consumers throughout a specified geographic area. In essence, the Poolco model is one in which there are no REPs, and the wholesale and retail markets for electricity are combined into a single commodity market. In the Poolco model, there are no explicit provisions for the purchase and sale of generation capacity. Instead, the pool is able to attract generation when available capacity is scarce by raising the commodity price for electricity. The two-pronged effect from raising price is to decrease demand as well as to increase supply.

In a highly competitive environment, there is a convergence of the Poolco model and the REP model of retail electric competition that includes both wholesale and retail markets. By convergence is meant that both market structures result in the same market-clearing prices for electricity. In short, this convergence will occur because the hedging activities of power marketers will result in the same outcomes as the market price determination activities of the Poolco.

When supply prices are below demand prices, power marketers will buy supply, which they will then sell for a profit. Where market information is easily accessed, these differences in demand and supply prices will be known by all competitors, so no single competitor can make huge profits. In this case, with the increased purchases of supplies, the supply price will increase and with the increased provision of demands, the demand price will decrease. When the two prices are equal, there is no longer any reason to hedge. This market-based set of bilateral transactions are identical to the more formal actions of a Poolco when faced with the same information.

As a matter of preference between the two market structures, the issue is really one of perceptions about what is called "price transparency," in which concerns are expressed about the assumption that market information will be easily available to all power marketers. That argument should be taken up in a different venue than what is being considered in this proposed merger. What is important here is, that in regards to modeling retail electric competition, it does not matter whether the REP or Poolco model is used, the pricing results will be the same.

Q. WHAT IS THE MINIMUM LEVEL OF COMPETITION THAT IS ACCEPTABLE FOR RETAIL ELECTRIC COMPETITION?

A. In order to meet concerns about possible collusion, it is imperative that there be at least three (preferably four) principal competitors within the relevant geographic market. In order to meet concerns about dominant firm behavior, these principal competitors should be of approximately the same size. If there are only three principal competitors, then there should be in addition at least two significant competitors that have approximately half the market share of the principal competitors, and there will also be a competitive fringe that should make up at least as much of the market share as the largest principal competitor. Based on these minimal criteria, the market shares and concentrations would be the following:

TABLE 1 MINIMAL COMPETITIVE CONDITIONS FOR RETAIL ELECTRICITY COMPETITION			
Type of Competitor	**Number of Competitors**	**Market Share % / Competitor**	**Concentration HHIs**
Principal	3	20%	1,200
Significant	2	10%	200
Fringe	10	2%	40
Total	**15**	**100%**	**1,440**

If the two significant competitors were to merge, then the HHI would increase from 1,440 to $4*(20^2) + 10*(2^2) = 4*(400) + 10*(4) = 1{,}600 + 40 = 1{,}640$. What is more likely to happen is that the significant competitors will be importers into the region, whose ability to compete is restricted by the availability of transmission. In any case, if the proposed merger between KCPL and Western is approved, it is highly unlikely that the North SPP Region will meet the minimal competitive conditions for retail electric competition.

Q. ASSUMING THAT THE MERGER IS APPROVED, WHAT MITIGATIONS WILL BE REQUIRED TO MEET THESE MINIMAL COMPETITIVE CONDITIONS FOR RETAIL ELECTRIC COMPETITION?

A. At this time, it is not known what conditions will occur at the time of retail electric competition in Missouri. For example, in order for generation from SPA to participate in a competitive electric market, the United States Congress would have to pass legislation that would relieve the SPA of its obligation to provide power to small municipals and cooperatives. In this case, that same legislation would likely require the sale of SPA generation resources to private companies. In addition, proposed legislation in Missouri would give cooperatives and municipals the choice not to participate in retail electric competition. This legislation could result in the removal of AEC's generation from being a competitor in the North SPP Region. With a KCPL – Western merger, this would leave one dominant supplier in the region, with Entergy being the only other possible significant competitor. I should point out that even without the merger of KCPL and Western, if SPA and AEC are not fully in the competitive market for electricity in the North SPP Region, the competitive environment is questionable, but with the merger, that environment becomes absolutely bleak.

In a bleak competitive environment, the only effective mitigation is to require the dominant supplier to sell a major portion of its generation to non-affiliated REPs. If SPP and AEC are not market participants in retail electric competition, I would recommend that the merged entity be required to sell at least two thirds of its existing generation in order to meet the minimum competitive conditions for retail electric competition.

Q. WHAT DO YOU MEAN BY SALE OF GENERATION?

A. Sale of generation to non-affiliated REPs can occur in one of two ways. First, the merged company could divest some of its generation assets. Second, the merged company could enter into long-term power contracts with non-affiliated REPs.

Q. WHAT EXACTLY DO YOU MEAN BY DIVEST SOME OF ITS GENERATION ASSETS?

A. Divestiture of generation assets means the outright sale of the physical assets to another entity, preferably an entity that wants to compete for retail electric business within the relevant geographic market in which those physical assets are located. The sale of these assets will provide a merged KCPL-Western Company funds with which to purchase generation assets in other markets in which it may want to compete as a REP. For example, the merger applicants could purchase generation assets from Ameren and Entergy. I believe that divestiture needs to be done in a way that allows the market to properly evaluate the generation assets as if those generation assets were to be used in a highly competitive market environment. Therefore, any single buyer of these assets should be restricted from buying more capacity than the maximum amount that the owner is allowed to keep for itself.

III. VERTICAL MARKET POWER ISSUES

III.A TRANSMISSION COSTS

Q. WHAT DETERMINES THE COST OF TRANSMISSION SERVICE TO A CUSTOMER WITHIN THE SPP?

A. In part, transmission costs are based on a SPP regional tariff approved by the FERC. The current SPP charges for regional transmission service for short-term (less than one year), point-to-point service are megawatt-mile (MW-mile) charges. The MW-mile charge is a distance sensitive rate in which users are required to contribute to covering the embedded transmission costs of the transmission system based on their use of the system. Recently, the SPP has received FERC approval to offer long-term point-to-point service where the transmission customer will pay a single rate – the embedded cost transmission rate of the utility in which the destination, i.e., the load to be served, is located. Prospectively, the SPP is working on providing network service and short-term, point-to-point service on a similar basis to long-term, point-to-point service, i.e., a single rate based on the transmission costs of the utility where the destination is located. What is important for this proceeding is that transmission owners within the SPP have the option of either taking/offering transmission service under the SPP regional tariffs or taking/offering transmission service under their separate transmission tariffs.

Q. WHY IS THE OPTION TO TAKE REGIONAL TRANSMISSION SERVICE IMPORTANT TO THIS PROCEEDING?

A. Not having the option to take regional transmission service results in pancaked transmission rates for purchases of generation located outside the control area of the utility where the load which is sought to be served is located. Pancaked transmission rates occur when a customer wants to purchase from a REP whose generation is located outside the utility control area in which the customer is located. In this case, the REP will have to pay transmission charges in the utility control area in which the generation is located, in the utility control area in which the customer is located, and in all other control areas between these two that are on a contract path which the electricity is deemed to take. This pancaking of transmission rates makes generation outside the utility's control area less competitive than generation inside the utility's control area. This constitutes a non-economic barrier to competition that gives the utility vertical market power within its own control area.

Q. WHY SHOULD CUSTOMERS NOT HAVE TO PAY FOR THEIR USE OF THE TRANSMISSION SYSTEMS OF OTHER UTILITIES?

A. Customers should have to pay for the incremental costs that their use of the transmission systems of other utilities cause. This is not the issue with rate pancaking or the application of any form of distance sensitive rates. Rate pancaking and distance sensitive rates are designed to collect embedded (sunk) costs, not incremental costs caused by a particular transmission transaction. The recovery of sunk costs is a matter of policy that should take into account all issues that affect whether the rates are just and reasonable. For example, the transmission costs within KCPL's service territory are not distance sensitive (e.g., there is no charging of higher transmission costs to rural customers than to urban customers due to the distance to the customer on the transmission system). One reason for this situation is that the transmission system is viewed as a network that connects all generation to all load within the service territory and is therefore used by all customers based on their load requirements, not on their location within the service territory. For regional use of the transmission system, the recovery of sunk costs should also be based on policy considerations. In my opinion, the need to prevent non-economic barriers to competition is a primary policy consideration that should be applied to eliminate pancaked and distance sensitive transmission rates.

Q. WHY SHOULD THE ELIMINATION OF PANCAKED AND DISTANCE SENSITIVE TRANSMISSION RATES BE CONSIDERED IN THE CONTEXT OF THIS PROPOSED MERGER OF KCPL AND WESTERN?

A. If the Commission approves the merger of KCPL and Western, the merged company will have control of a larger portion of the transmission system than the individual companies did. This will reduce transmission customer alternatives if the merged company decides not to participate in the SPP regional tariff.

Q. SHOULD THE COMMISSION CONDITION ITS APPROVAL OF THE MERGER BASED ON ANY CONCERNS THAT YOU HAVE ADDRESSED IN YOUR TESTIMONY?

A. Yes. Both Western and KCPL are currently participating in the SPP regional tariff. The Commission should require assurance from these companies that if the Commission approves the merger they will continue to offer transmission service through the SPP regional tariff, if such transmission service continues to be available. The Commission also should require assurance from Western and KCPL that if for some reason the SPP regional tariff does not continue to be available, the merged entity will seek another regional transmission organization offering a regional tariff at the earliest possible date (e.g., both a MAPP regional tariff and the Midwest ISO regional tariff may be viable alternatives). From available alternatives, the choice should be a tariff that offers the most complete level of regional transmission service (both short-term and long-term, point-to-point service, as well as network service) with transmission rates that are not pancaked or distance sensitive.

III.B TRANSMISSION AVAILABILITY

Q. WHAT DETERMINES THE AVAILABILITY OF TRANSMISSION WITHIN THE SPP?

A. The availability of transmission within the SPP occurs at two levels. First, if the service is requested on the facilities of transmission owners that have agreed to provide the transmission service being requested through the SPP agency agreement, then the SPP is the Tariff Administrator for that service. In this case, the transmission service request is made of the SPP and the SPP determines the availability of the service. If the request for service also involves transmission facilities of a transmission owner that has not signed the agency agreement with the SPP to provide transmission service, then the transmission customer must determine whether the transmission service being requested is available, and if there is available transmission capability (ATC), schedule the transmission service with the transmission owner.

The second type of availability of transmission within the SPP region is related to the security of the transmission system. If, for whatever reason, a part of the transmission system is operating at a level above the SPP security guidelines, then a request for line loading relief by the control area operator where the problem is occurring will be made to the SPP Security Coordinator. If the SPP Security Coordinator determines that the problem is valid, then transmission service will be curtailed in an effort to relieve the problem. The SPP currently has a generation redispatch procedure for relieving transmission security problems. The rationale behind generation redispatch is to minimize, and hopefully eliminate, the need to curtail firm load. This objective is viable whenever a different dispatch of generation relieves a security problem and result in all end-use customers seeking firm service being able to obtain that service.

Q. DO TRANSMISSION OWNING UTILITIES IN THE SPP REGION HAVE A CHOICE REGARDING WHETHER THEY OR THE SPP DETERMINE TRANSMISSION AVAILABILITY?

A. Yes, they do. If a transmission owning utility within the SPP has not signed an agency agreement with respect to the SPP regional tariff, then the SPP does not act as the Tariff Administrator for that transmission owning utility. In this case, the transmission owning utility determines the ATC for its control area. With respect to transmission system security, all transmission utilities within the SPP region have agreed that the SPP will act as the Security Coordinator for the SPP region.

Q. ARE THESE COMPETITIVE CONCERNS WITH RESPECT TO TRANSMISSION AVAILABILITY?

A. Yes. The primary competitive concern is that if the transmission utility can determine the ATC within its control area, it can manipulate the ATC to favor that utility's own generation.

Q. HOW SHOULD THIS CONCERN BE ADDRESSED?

A. This concern is mitigated by the recommendation I previously made with respect to the merger applicants being a part of a regional transmission organization. I would add that the regional transmission organization must be the Tariff Administrator having the authority to determine the availability of transmission service, and must be the Security Coordinator having the authority to determine when and how line loading relief is implemented.

III.C TRANSMISSION PLANNING

Q. HOW IS TRANSMISSION PLANNING DONE WITHIN THE SPP?

A. Currently, transmission planning is coordinated within the SPP. Individual transmission owners make decisions about how to upgrade and expand their facilities, but voluntarily submit those plans for input from other transmission providers within the SPP. Under the proposal currently being considered by the SPP Regional Price Working Group (RPWG), changes to current coordination procedures are being considered.

As a background to potential changes with respect to transmission planning, the RTO proposal currently being considered by the SPP Independent System Operator (ISO) Task Force, would change the governance and membership structure of the SPP. Under this proposal, there would be three types of SPP members: 1) Transmission Owners; 2)

Transmission Customers; and 3) Others. The reformed Board of Directors (Board) of the SPP would have equal representation from all three groups, with the third group being Board members elected from candidates that have no operational or financial interests with respect to transmission owners or transmission customers.

The SPP RPWG is currently discussing the concept of giving the reformed SPP Board the authority to require transmission facilities to be upgraded or expanded. This proposal would go beyond the current SPP coordinated planning requirements.

Q. HOW IS TRANSMISSION PLANNING IMPORTANT TO THE COMPETITIVE GENERATION ENVIRONMENT WITHIN THE SPP REGION?

A. If a transmission customer requests transmission service, and there is not sufficient ATC to grant that service, then the transmission customer can request that the transmission provider perform a transmission system impact study. The results of this study will set out the expansion or upgrade of transmission facilities necessary to provide the transmission service being requested. In addition, the transmission system impact study will give an estimate of what the costs are for engaging in the expansion or upgrade. Under a structure, like the one currently being considered by the SPP, the regional transmission organization would be the entity performing the transmission system impact studies. Thus, such studies would be performed on an independent basis. Without a regional transmission organization to conduct independent transmission system impact studies, this transmission planning function would be left up to the individual utility that refused transmission service because of insufficient ATC. As with the determination of ATC, the utility could perform such studies in a way that would favor the competitive position of its own generating facilities.

Q. HOW SHOULD THIS CONCERN BE ADDRESSED?

A. This concern is mitigated by the recommendation I previously made with respect to the merger applicants being a part of a regional transmission organization. I would add that the regional transmission organization must have the responsibility for performing transmission system impact studies. I am somewhat uncomfortable with the regional transmission organization having the absolute authority to mandate upgrades of and expansions to transmission systems. In this regard, the issue of incentives for building new transmission is one that is being debated throughout the country, and there are associated issues with respect to both congestion management and congestion pricing that need to be worked out. Part of this debate is whether or not transmission service should be provided by companies that have no affiliated interest in other forms of the regulated utility business; i.e., so called TRANSCOs (transmission companies), which are transmission owning utilities seeking to maximize net operating income. Because this is currently an ongoing and very complex debate, I will recommend simply that the RTO or similar organization have in place policies that promote the timely upgrade or addition of new transmission facilities.

IV. REQUIRED MARKET POWER MITIGATION MEASURES

Q. WHAT IS THE PURPOSE OF THIS FINAL SECTION OF YOUR REBUTTAL TESTIMONY?

A. The purpose of this section is to set out a list of the specific recommendations that have been made throughout my rebuttal testimony.

Q. WITH RESPECT TO MITIGATION OF HORIZONTAL MARKET POWER, WHAT ARE THE STAFF'S SPECIFIC RECOMMENDATIONS?

A. Should the Commission decide to approve the merger of KCPL and Western, as conditions to such approval, in order that the merger not be detrimental to the public interest, the Staff recommends that the Commission direct the following respecting the determination and mitigation of horizontal market power:

A. KCPL and Western must agree that at a time and in a proceeding to be determined by the Missouri Public Service Commission, which is either required by legislation or related to the start of retail electricity competition in Missouri, the merged entity will file a retail market power study focusing on the merged entity's horizontal market power. The market power study must meet the following conditions:

1. For purposes of determining the extent of horizontal market power the study shall model the competitive market for retail electricity, including the following assumptions:
    a. All generation is available for competitive bid – there is no native load;
    b. Transmission costs include only losses and congestion pricing – embedded transmission costs are collected through non-distance sensitive access charges, not usage charges;
    c. Transmission lines, capacities and constraints will be consistent with regional reliability council or regional transmission organization models used to determine transmission availability within each region that is modeled; and
    d. The model will determine as the base case, the economic dispatch of generation subject to transmission constraints, losses and congestion that is consistent with minimization of total generation costs through marginal cost bids from generators to meet hourly loads throughout an appropriate test year.

2. For purposes of determining the concentration of market power, the study shall assume that the relevant geographic market is the North SPP region, including the Associated Electric Cooperative, Inc. (AEC) and the Southwestern Power Administration service territories, unless the relevant geographic market is otherwise determined to be different based on the Department of Justice's "hypothetical monopolist test." [U.S. Department of Justice and Federal Trade Commission, Horizontal Merger Guidelines, 57 Fed. Reg. 41,552 (1992)] If the merged entity applies this

"hypothetical monopolist test," it shall use a model that meets the conditions specified in part A.1 above.

3. For purposes of determining the merged entity's ability to exercise market power through strategic pricing of electricity, the merged entity shall perform an analysis that considers various pricing strategies, which it might use to increase profits above the marginal cost bidding of generation. The merged entity shall perform the pricing strategy analysis using a model that meets the conditions specified in part A.1 above.

B. KCPL and Western must agree that in the context of the horizontal market power filing specified in part A above, if the Missouri Public Service Commission determines that there is a need to mitigate the horizontal market power of the merged entity, then the merged entity will proceed as follow:

1. For mitigation measures involving generation (e.g., required wholesale sales of generation or divestiture of generation), the relevant generating plants are those that are assigned or allocated to serve KCPL's Missouri retail customers per the Allocations Agreement proposed by the Staff in this case.

2. Should the Missouri Public Service Commission order divestiture of generation as mitigation to meet what the Missouri Public Service Commission determines to be the minimum level of competition acceptable for retail electricity competition, the merged entity will not appeal the Missouri Commission's order to divest generation.

Q. WITH RESPECT TO MITIGATION OF VERTICAL MARKET POWER, WHAT ARE THE STAFF'S SPECIFIC RECOMMENDATIONS?

A. Should the Commission decide to approve the merger of KCPL and Western, as conditions to such approval, in order that the merger not be detrimental to the public interest, the Staff recommends that the Commission direct the following respecting the determination and mitigation of vertical market power:

KCPL and Western must agree that at or before the time that the Missouri Public Service Commission sets for market power proceedings, the merged entity will become a member of a regional transmission organization. In this respect the merged entity will continue to offer transmission service through the SPP regional tariff, if available, and as long as the SPP meets the conditions set out below. If the SPP does not meet these conditions, then the merged entity will join a regional transmission organization that most closely meets these conditions.

A. With respect to regional transmission rates, the regional transmission organization should offer:
   1. Transmission rates for collecting embedded transmission costs that are not pancaked or distance sensitive; and
   2. Provide regional transmission service for both short-term and long-term, point-to-point service, as well as network service.

B. With respect to governance, control and authority, the regional transmission organization must:
   1. Be the Tariff Administrator having the authority to determine the availability of transmission service;
   2. Be the Security Coordinator having the authority to determine when and how line loading relief is implemented; and
   3. Have an independent board of directors.

C. With respect to transmission planning, upgrades and expansion, the regional transmission organization must:
   1. Coordinate transmission planning throughout the region;
   2. Have the responsibility for transmission system impact studies being performed;
   3. Have in place policies that promote the timely upgrade or addition of new transmission facilities; and
   4. If the above conditions (1-3) are not met, then the merged entity will make timely upgrades or additions to the transmission system as required by the regional transmission organization.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of the Joint Application of Western Resources, Inc. and Kansas City Power & Light Company for approval of the merger of Kansas City Power & Light Company with Western Resources, Inc. and for other related relief.	)))))	Case No. EM-97-515

AFFIDAVIT OF MICHAEL S. PROCTOR

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Michael S. Proctor, of lawful age, on his oath states: that he has participated in the preparation of the foregoing written testimony in question and answer form, consisting of 50 pages of testimony to be presented in the above case, that the answers in the attached written testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.

Michael S Proctor
Michael S. Proctor

Subscribed and sworn to before me this 22nd day of April, 1999.

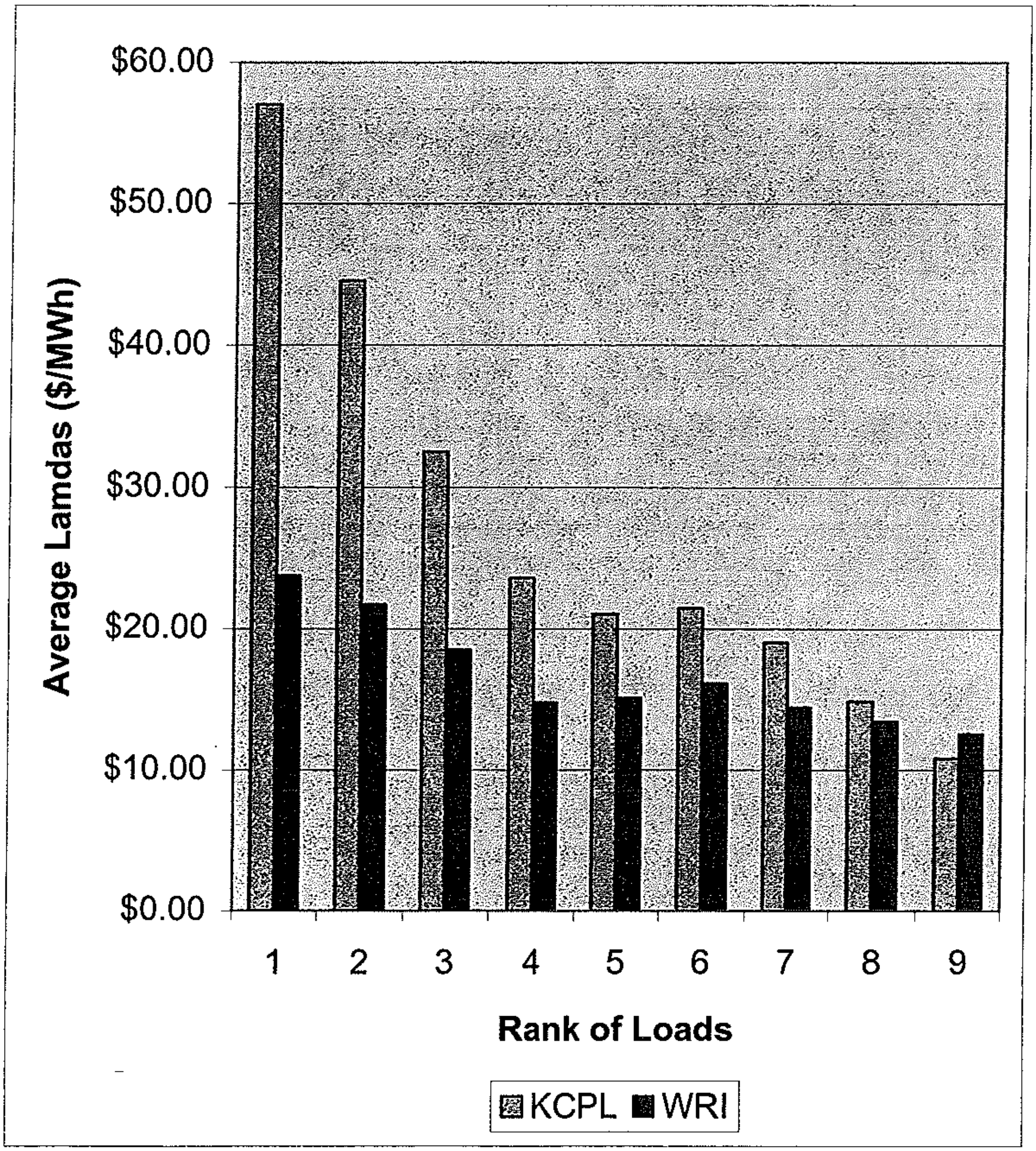
Joyce C. Neuner
Notary Public

Joyce C. Neuner
Notary Public, State of Missouri
County of Osage
My Commission Exp. 06/18/2001

My commission expires

Average System Lambdas by Load Levels
1997 ($/MWh)

	Highest 100 Hours	Next 250 Hours	Next 400 Hours	Next 600 Hours	Next 800 Hours	Next 1,000 Hours	Next 1,600 Hours	Next 1,500 Hours	Next 2,510 Hours
KCPL	$57.03	$44.53	$32.52	$23.63	$21.04	$21.48	$19.03	$14.84	$10.82
WRI	$23.74	$21.72	$18.50	$14.75	$15.08	$16.12	$14.41	$13.40	$12.52



SUMMARY OF ECONOMIC CAPACITY, MARKET SHARES AND HHI MEASURES
PEAK HOURS - HIGHEST 750 HOURS

TABLE 1: HIGHEST 100 HOURS

	MW of Economic Capacity				Initial	Percentage Market Shares				Change in
Destination Markets	WERE	KCPL	Incumbent	TOTAL	HHI	%WERE	%KCPL	%Merged	%Incumbent	HHI
Western Resources	3,184	206	3,184	7,072	2,195	45.02%	2.91%	47.94%	45.02%	262
Kansas City Power & Light	297	3,277	3,277	7,680	2,035	3.87%	42.67%	46.54%	42.67%	330
Ameren	214	140	9,836	16,329	3,719	1.31%	0.86%	2.17%	60.24%	2
Associated Electric Cooperatives	500	284	3,327	9,584	1,490	5.22%	2.96%	8.18%	34.71%	31
Empire District Electric	216	141	867	4,172	830	5.18%	3.38%	8.56%	20.78%	35
Missouri Public Service	321	229	635	3,948	743	8.13%	5.80%	13.93%	16.08%	94
St. Joseph Light & Power	45	29	358	1,001	1,565	4.50%	2.90%	7.39%	35.76%	26
Kansas City, KS BPU	138	79	512	2,385	813	5.79%	3.31%	9.10%	21.47%	38
Central and Southwest	337	232	5,411	10,371	2,932	3.25%	2.24%	5.49%	52.17%	15
Oklahoma Gas & Electric	171	97	5,170	7,754	4,521	2.21%	1.25%	3.46%	66.68%	6
MidAmerican Entergy	510	351	3,068	9,065	1,467	5.63%	3.87%	9.50%	33.84%	44
Omaha Public Power District	211	145	1,563	3,872	1,900	5.45%	3.74%	9.19%	40.37%	41
Lincoln Electric System	375	243	934	6,308	724	5.94%	3.85%	9.80%	14.81%	46
Nebraska Public Power District	373	247	1,679	6,907	1,008	5.40%	3.58%	8.98%	24.31%	39

TABLE 2: NEXT HIGHEST 250 HOURS

	MW of Economic Capacity				Initial	Percentage Market Shares				Change in
Destination Markets	WERE	KCPL	Incumbent	TOTAL	HHI	%WERE	%KCPL	%Merged	%Incumbent	HHI
Western Resources	3,184	251	3,184	7,040	2,221	45.23%	3.57%	48.79%	45.23%	323
Kansas City Power & Light	296	2,846	2,846	7,217	1,796	4.10%	39.43%	43.54%	39.43%	323
Ameren	213	142	9,836	16,323	3,722	1.30%	0.87%	2.17%	60.26%	2
Associated Electric Cooperatives	497	341	3,327	9,608	1,497	5.17%	3.55%	8.72%	34.63%	37
Empire District Electric	212	136	855	4,164	828	5.09%	3.27%	8.36%	20.53%	33
Missouri Public Service	322	220	635	3,942	749	8.17%	5.58%	13.75%	16.11%	91
St. Joseph Light & Power	47	31	277	923	1,226	5.09%	3.36%	8.45%	30.01%	34
Kansas City, KS BPU	160	110	512	2,380	820	6.72%	4.62%	11.34%	21.51%	62
Central and Southwest	349	240	5,006	9,995	2,728	3.49%	2.40%	5.89%	50.09%	17
Oklahoma Gas & Electric	189	130	3,668	6,390	3,398	2.96%	2.03%	4.99%	57.40%	12
MidAmerican Entergy	700	497	2,684	8,728	1,334	8.02%	5.69%	13.71%	30.75%	91
Omaha Public Power District	245	168	1,563	3,784	1,900	6.47%	4.44%	10.91%	41.31%	57
Lincoln Electric System	432	269	840	6,295	670	6.86%	4.27%	11.14%	13.34%	59
Nebraska Public Power District	609	419	1,667	9,480	777	6.42%	4.42%	10.84%	17.58%	57

TABLE 3: NEXT HIGHEST 400 HOURS

	MW of Economic Capacity				Initial	Percentage Market Shares				Change in
Destination Markets	WERE	KCPL	Incumbent	TOTAL	HHI	%WERE	%KCPL	%Merged	%Incumbent	HHI
Western Resources	3,184	251	3,184	6,750	2,414	47.17%	3.72%	50.89%	47.17%	351
Kansas City Power & Light	401	2,688	2,688	8,083	1,373	4.96%	33.25%	38.22%	33.25%	330
Ameren	259	148	9,836	16,622	3,592	1.56%	0.89%	2.45%	59.17%	3
Associated Electric Cooperatives	583	398	3,327	9,579	1,505	6.09%	4.15%	10.24%	34.73%	51
Empire District Electric	213	132	662	3,810	705	5.59%	3.46%	9.06%	17.38%	39
Missouri Public Service	323	221	635	3,938	751	8.20%	5.61%	13.81%	16.12%	92
St. Joseph Light & Power	48	33	257	906	1,147	5.30%	3.64%	8.94%	28.37%	39
Kansas City, KS BPU	189	118	477	2,254	899	8.39%	5.24%	13.62%	21.16%	88
Central and Southwest	358	246	3,861	8,897	2,141	4.02%	2.76%	6.79%	43.40%	22
Oklahoma Gas & Electric	206	141	2,532	5,171	2,554	3.98%	2.73%	6.71%	48.97%	22
MidAmerican Entergy	351	480	2,684	7,814	1,601	4.49%	6.14%	10.63%	34.35%	55
Omaha Public Power District	135	184	1,490	3,659	1,997	3.69%	5.03%	8.72%	40.72%	37
Lincoln Electric System	540	370	840	6,053	729	8.92%	6.11%	15.03%	13.88%	109
Nebraska Public Power District	906	620	1,667	10,110	795	8.96%	6.13%	15.09%	16.49%	110

SUMMARY OF ECONOMIC CAPACITY, MARKET SHARES AND HHI MEASURES
HIGHER INTERMEDIATE HOURS - NEXT HIGHEST 2,400 HOURS

TABLE 4: NEXT HIGHEST 600 HOURS

	MW of Economic Capacity				Initial	Percentage Market Shares				Change in
Destination Markets	WERE	KCPL	Incumbent	TOTAL	HHI	%WERE	%KCPL	%Merged	%Incumbent	HHI
Western Resources	3,069	208	3,069	6,273	2,195	48.92%	3.32%	52.24%	48.92%	324
Kansas City Power & Light	459	2,188	2,188	7,455	2,035	6.16%	29.35%	35.51%	29.35%	361
Ameren	261	180	9,453	16,192	3,719	1.61%	1.11%	2.72%	58.38%	4
Associated Electric Cooperatives	675	438	2,080	8,130	1,490	8.30%	5.39%	13.69%	25.58%	89
Empire District Electric	204	140	474	3,575	830	5.71%	3.92%	9.62%	13.26%	45
Missouri Public Service	334	237	520	3,877	743	8.61%	6.11%	14.73%	13.41%	105
St. Joseph Light & Power	63	43	257	869	1,565	7.25%	4.95%	12.20%	29.57%	72
Kansas City, KS BPU	128	105	443	2,268	813	5.64%	4.63%	10.27%	19.53%	52
Central and Southwest	358	245	3,861	8,877	2,932	4.03%	2.76%	6.79%	43.49%	22
Oklahoma Gas & Electric	213	146	2,532	5,161	4,521	4.13%	2.83%	6.96%	49.06%	23
MidAmerican Entergy	186	565	2,680	9,356	1,467	1.99%	6.04%	8.03%	28.64%	24
Omaha Public Power District	88	191	1,490	3,589	1,900	2.45%	5.32%	7.77%	41.52%	26
Lincoln Electric System	314	430	196	5,034	724	6.24%	8.54%	14.78%	3.89%	107
Nebraska Public Power District	550	752	1,667	9,568	1,008	5.75%	7.86%	13.61%	17.42%	90

TABLE 5: NEXT HIGHEST 800 HOURS

	MW of Economic Capacity				Initial	Percentage Market Shares				Change in
Destination Markets	WERE	KCPL	Incumbent	TOTAL	HHI	%WERE	%KCPL	%Merged	%Incumbent	HHI
Western Resources	3,069	193	3,069	6,346	2,552	48.36%	3.04%	51.40%	48.36%	294
Kansas City Power & Light	496	2,177	2,177	7,069	1,273	7.02%	30.80%	37.81%	30.80%	432
Ameren	301	206	9,453	16,100	3,544	1.87%	1.28%	3.15%	58.71%	5
Associated Electric Cooperatives	705	457	2,080	7,973	1,128	8.84%	5.73%	14.57%	26.09%	101
Empire District Electric	206	142	474	3,557	640	5.79%	3.99%	9.78%	13.33%	46
Missouri Public Service	295	238	520	3,771	799	7.82%	6.31%	14.13%	13.79%	99
St. Joseph Light & Power	64	45	232	844	1,143	7.58%	5.33%	12.91%	27.49%	81
Kansas City, KS BPU	128	105	443	2,270	870	5.64%	4.63%	10.26%	19.52%	52
Central and Southwest	369	252	3,861	8,918	2,140	4.14%	2.83%	6.96%	43.29%	23
Oklahoma Gas & Electric	222	152	2,532	5,147	2,581	4.31%	2.95%	7.27%	49.19%	25
MidAmerican Entergy	232	707	2,680	10,552	1,253	2.20%	6.70%	8.90%	25.40%	29
Omaha Public Power District	17	256	1,490	3,523	2,274	0.48%	7.27%	7.75%	42.29%	7
Lincoln Electric System	310	457	196	5,067	897	6.12%	9.02%	15.14%	3.87%	110
Nebraska Public Power District	389	651	1,667	9,451	1,048	4.12%	6.89%	11.00%	17.64%	57

TABLE 3: NEXT HIGHEST 1,000 HOURS

	MW of Economic Capacity				Initial	Percentage Market Shares				Change in
Destination Markets	WERE	KCPL	Incumbent	TOTAL	HHI	%WERE	%KCPL	%Merged	%Incumbent	HHI
Western Resources	3,069	193	3,069	6,346	2,552	48.36%	3.04%	51.40%	48.36%	294
Kansas City Power & Light	492	2,177	2,177	7,110	1,258	6.92%	30.62%	37.54%	30.62%	424
Ameren	310	212	9,419	15,724	3,685	1.97%	1.35%	3.32%	59.90%	5
Associated Electric Cooperatives	744	482	2,080	7,800	1,196	9.54%	6.18%	15.72%	26.67%	118
Empire District Electric	217	149	474	3,572	612	6.08%	4.17%	10.25%	13.27%	51
Missouri Public Service	168	247	460	3,658	789	4.59%	6.75%	11.34%	12.58%	62
St. Joseph Light & Power	66	47	232	845	1,155	7.81%	5.56%	13.37%	27.46%	87
Kansas City, KS BPU	148	131	443	2,249	870	6.58%	5.82%	12.41%	19.70%	77
Central and Southwest	408	279	3,527	8,553	1,996	4.77%	3.26%	8.03%	41.24%	31
Oklahoma Gas & Electric	226	155	2,532	5,137	2,594	4.40%	3.02%	7.42%	49.29%	27
MidAmerican Entergy	279	607	1,874	10,725	1,090	2.60%	5.66%	8.26%	17.47%	29
Omaha Public Power District	19	281	1,490	3,508	2,325	0.54%	8.01%	8.55%	42.47%	9
Lincoln Electric System	181	552	196	5,856	944	3.09%	9.43%	12.52%	3.35%	58
Nebraska Public Power District	217	662	1,667	9,351	1,081	2.32%	7.08%	9.40%	17.83%	33

SUMMARY OF ECONOMIC CAPACITY, MARKET SHARES AND HHI MEASURES
LOWER INTERMEDIATE & OFF-PEAK HOURS - LOWEST 5610 HOURS

TABLE 7: NEXT HIGHEST 1,600 HOURS

	MW of Economic Capacity				Initial	Percentage Market Shares				Change in
Destination Markets	WERE	KCPL	Incumbent	TOTAL	HHI	%WERE	%KCPL	%Merged	%Incumbent	HHI
Western Resources	3,017	190	3,017	6,299	2,512	47.90%	3.02%	50.91%	47.90%	289
Kansas City Power & Light	536	2,177	2,177	7,228	1,253	7.42%	30.12%	37.53%	30.12%	447
Ameren	310	212	9,419	15,837	3,634	1.96%	1.34%	3.30%	59.47%	5
Associated Electric Cooperatives	713	462	2,080	7,883	1,144	9.04%	5.86%	14.91%	26.39%	106
Empire District Electric	216	149	474	3,597	601	6.01%	4.14%	10.15%	13.18%	50
Missouri Public Service	296	221	460	3,729	737	7.94%	5.93%	13.86%	12.34%	94
St. Joseph Light & Power	66	43	232	845	1,147	7.81%	5.09%	12.90%	27.46%	79
Kansas City, KS BPU	186	112	443	2,214	855	8.40%	5.06%	13.46%	20.01%	85
Central and Southwest	417	285	3,171	8,224	1,798	5.07%	3.47%	8.54%	38.56%	35
Oklahoma Gas & Electric	221	151	2,532	5,122	2,604	4.31%	2.95%	7.26%	49.43%	25
MidAmerican Entergy	231	503	1,874	9,757	1,051	2.37%	5.16%	7.52%	19.21%	24
Omaha Public Power District	19	276	1,490	3,552	2,250	0.53%	7.77%	8.31%	41.95%	8
Lincoln Electric System	297	390	196	5,400	862	5.50%	7.22%	12.72%	3.63%	79
Nebraska Public Power District	507	606	1,667	9,693	961	5.23%	6.25%	11.48%	17.20%	65

TABLE 8: NEXT HIGHEST 1,500 HOURS

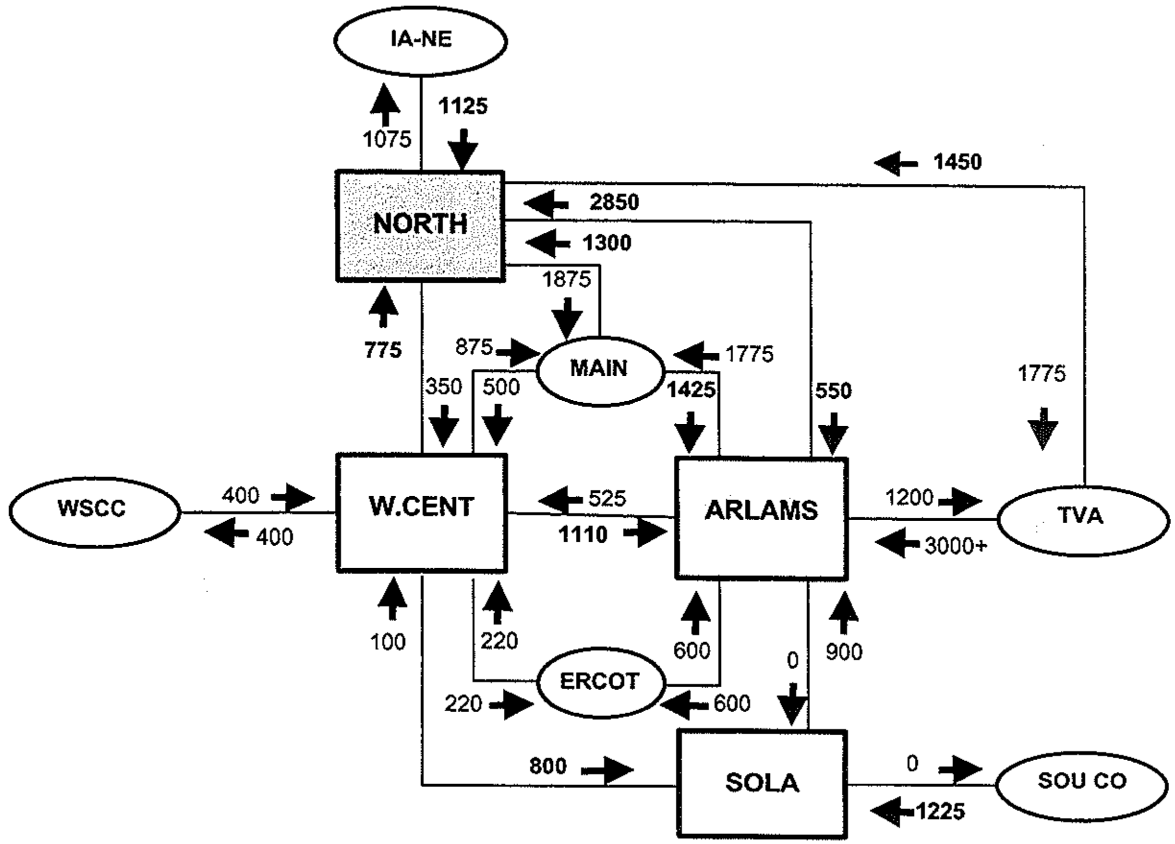
	MW of Economic Capacity				Initial	Percentage Market Shares				Change in
Destination Markets	WERE	KCPL	Incumbent	TOTAL	HHI	%WERE	%KCPL	%Merged	%Incumbent	HHI
Western Resources	1,349	197	1,349	4,580	1,283	29.45%	4.30%	33.76%	29.45%	253
Kansas City Power & Light	298	1,108	1,108	5,772	899	5.16%	19.20%	24.36%	19.20%	198
Ameren	336	218	8,456	14,134	3,685	2.38%	1.54%	3.92%	59.83%	7
Associated Electric Cooperatives	745	384	2,080	7,734	1,200	9.63%	4.97%	14.60%	26.89%	96
Empire District Electric	259	177	474	3,475	637	7.45%	5.09%	12.55%	13.64%	76
Missouri Public Service	239	211	460	3,686	756	6.48%	5.72%	12.21%	12.48%	74
St. Joseph Light & Power	36	46	202	816	1,116	4.41%	5.64%	10.05%	24.75%	50
Kansas City, KS BPU	118	97	443	2,256	884	5.23%	4.30%	9.53%	19.64%	45
Central and Southwest	444	277	2,894	7,889	1,687	5.63%	3.51%	9.14%	36.68%	40
Oklahoma Gas & Electric	264	134	2,165	4,576	2,448	5.77%	2.93%	8.70%	47.31%	34
MidAmerican Entergy	340	739	1,734	9,982	1,031	3.41%	7.40%	10.81%	17.37%	50
Omaha Public Power District	105	229	1,490	3,604	2,107	2.91%	6.35%	9.27%	41.34%	37
Lincoln Electric System	204	444	65	5,518	979	3.70%	8.05%	11.74%	1.18%	59
Nebraska Public Power District	283	615	1,667	9,028	1,022	3.13%	6.81%	9.95%	18.46%	43

TABLE 9: NEXT HIGHEST 2,510 HOURS

	MW of Economic Capacity				Initial	Percentage Market Shares				Change in
Destination Markets	WERE	KCPL	Incumbent	TOTAL	HHI	%WERE	%KCPL	%Merged	%Incumbent	HHI
Western Resources	1,244	191	1,244	4,789	1,146	25.98%	3.99%	29.96%	25.98%	207
Kansas City Power & Light	139	791	791	5,050	1,079	2.75%	15.66%	18.42%	15.66%	86
Ameren	226	183	6,535	11,634	3,303	1.94%	1.57%	3.52%	56.17%	6
Associated Electric Cooperatives	472	388	2,080	7,591	1,241	6.22%	5.11%	11.33%	27.40%	64
Empire District Electric	292	176	404	3,242	699	9.01%	5.43%	14.44%	12.46%	98
Missouri Public Service	188	216	460	3,700	735	5.08%	5.84%	10.92%	12.43%	59
St. Joseph Light & Power	14	44	112	726	950	1.93%	6.06%	7.99%	15.43%	23
Kansas City, KS BPU	115	103	198	2,014	724	5.71%	5.11%	10.82%	9.83%	58
Central and Southwest	545	276	1,422	6,269	1,019	8.69%	4.40%	13.10%	22.68%	77
Oklahoma Gas & Electric	189	130	3,668	6,390	3,398	2.96%	2.03%	4.99%	57.40%	12
MidAmerican Entergy	343	746	1,268	9,456	994	3.63%	7.89%	11.52%	13.41%	57
Omaha Public Power District	20	135	1,420	3,420	2,280	0.58%	3.95%	4.53%	41.52%	5
Lincoln Electric System	36	526	0	4,758	1,373	0.76%	11.06%	11.81%	0.00%	17
Nebraska Public Power District	364	791	1,667	8,803	1,097	4.13%	8.99%	13.12%	18.94%	74

FIRST CONTINGENCY MAXIMUM TRANSFER CAPABILITY (MW)

SOUTHWEST POWER POOL: 1996 SUMMER PEAK TRANSMISSION ASSESSMENT



Schedule 3

ADJUSTMENTS TO MERGER APPLICANTS SHARES AND CONCENTRATIONS OF ECONOMIC CAPACITY FOR RELEVANT GEOGRAPHIC MARKET AREA

	Spann*		FCMTC	14 Mills Adjusted for Transmission Import Constraints				
	MW-EC	% Share	TO NORTH	MW-EC	% Share	Pre-HHI	Post-HHI	Change
North SPP Region								34.56%
Kansas City Power & Light	2,631	6.75%		2,631	14.28%	204		
Western Resources	3,734	9.58%		3,734	20.27%	411	1194	
Associated Electric Cooperative	2,280	5.85%		2,280	12.38%	153	153	
Board of Public Utilites - Kansas City, KS	290	0.74%		290	1.57%	2	2	
City of Coffeyville, KS	0	0.00%		0	0.00%	0		
City of McPherson, KS	0	0.00%		0	0.00%	0	0	
City of Winfield, KS	0	0.00%		0	0.00%	0	0	
City Utilities - Springfield, MO	178	0.46%		178	0.97%	1	1	
Empire District Electric	307	0.79%		307	1.67%	3	3	
Independence Power & Light	93	0.24%		93	0.50%	0	0	
Kansas Electric Power Cooperative	70	0.18%		70	0.38%	0	0	
Midwest Energy, Inc.	0	0.00%		0	0.00%	0	0	
Missouri Public Service & West Plains Energy	909	2.33%		909	4.94%	24	24	
St. Joseph Light & Power	121	0.31%		121	0.66%	0	0	
Sunflower Electric Power Cooperative	325	0.83%		325	1.76%	3	3	
	10,938	**28.07%**		**10,938**	**59.39%**	**803**	**1,382**	**579**
West Central SPP Region								
Grand River Dam Authority	1,280	3.28%		109	0.59%	0		
KAMO Electric Cooperative	200	0.51%		17	0.09%	0	0	
Northeast Texas Electric Cooperative	78	0.20%		7	0.04%	0		
Oklahoma Gas & Electric	2,530	6.49%		216	1.18%	1		
Oklahoma Municipal Power Authority	118	0.30%		10	0.05%	0		
Central and Southwest	2,502	6.42%		214	1.16%	1		
Southwestern Power Administration	2,079	5.34%		178	0.97%	1		
Southwestern Public Service	39	0.10%		3	0.02%	0		
Western Farmers Electric Cooperative	0	0.00%		0	0.00%	0		
	8,826	**22.65%**	**755**	**755**	**4.10%**	**2**		
South SPP								
Entergy	3,575	9.17%		2,799	15.20%	231		
Arkansas Electric Cooperative	65	0.17%		51	0.28%	0		
Central Lousiana Electric Company	0	0.00%		0	0.00%	0		
Southwestern Electric Power	0	0.00%		0	0.00%	0		
City of Alexandria, LA	0	0.00%		0	0.00%	0		
Cajun Electric Power Cooperative	0	0.00%		0	0.00%	0		
City of Lafayette	0	0.00%		0	0.00%	0		
City of Clarksdale, MS	0	0.00%		0	0.00%	0		
Louisiana Energy and Power Authority	0	0.00%		0	0.00%	0		
Sam Rayburn G&T	0	0.00%		0	0.00%	0		
	3,640	**9.34%**	**2,850**	**2,850**	**15.47%**	**231**		
MAIN								
Ameren	1,812	4.65%		587	3.19%	10		
Central Illinois Power Cooperative	0	0.00%		0	0.00%	0		
Illinois Power Company	2,198	5.64%		713	3.87%	15		
	4,010	**10.29%**	**1,300**	**1,300**	**7.06%**	**25**		
TVA								
Tennessee Valley Authority	**10,353**	**26.57%**	**1,450**	**1,450**	**7.87%**	**62**		
MAPP								
Cooperative Power	53	0.14%		50	0.27%	0		
IES Utilites	137	0.35%		128	0.70%	0		
Interstate Power Company	16	0.04%		15	0.08%	0		
Lincoln Electric System	0	0.00%		0	0.00%	0		
MidAmerica Energy	326	0.84%		306	1.66%	3		
Minnesota Power	12	0.03%		11	0.06%	0		
Nebrasska Public Service	247	0.63%		232	1.26%	2		
Northern States Power	212	0.54%		199	1.08%	1		
Northwestern Public Service	10	0.03%		9	0.05%	0		
Omaha Public Power District	172	0.44%		161	0.88%	1		
Otter Tail Power	15	0.04%		14	0.08%	0		
	1,200	**3.08%**	**1,125**	**1,125**	**6.11%**	**7**		
TOTAL	**38,967**	**100.00%**		**18,418**	**100.00%**	**1,130**	**1,709**	**579**

* Merger Applicants Case 3: Regional Markets Assuming Zero Transmission Cost Excluding Southern Company

ADJUSTMENTS TO MERGER APPLICANTS SHARES AND CONCENTRATIONS OF ECONOMIC CAPACITY FOR RELEVANT GEOGRAPHIC MARKET AREA

	Spann*		FCMTC	20 Mills Adjusted for Transmission Import Constraints				
	MW-EC	% Share	TO NORTH	MW-EC	% Share	Pre-HHI	Post-HHI	Change
North SPP Region								32.69%
Kansas City Power & Light	2,631	3.51%		2,631	13.39%	179		
Western Resources	3,790	5.05%		3,790	19.29%	372	1068	
Associated Electric Cooperative	2,502	3.34%		2,502	12.74%	162	162	
Board of Public Utilites - Kansas City, KS	572	0.76%		572	2.91%	8	8	
City of Coffeyville, KS	0	0.00%		0	0.00%	0	0	
City of McPherson, KS	0	0.00%		0	0.00%	0	0	
City of Winfield, KS	0	0.00%		0	0.00%	0	0	
City Utilities - Springfield, MO	413	0.55%		413	2.10%	4	4	
Empire District Electric	399	0.53%		399	2.03%	4	4	
Independence Power & Light	131	0.17%		131	0.67%	0	0	
Kansas Electric Power Cooperative	70	0.09%		70	0.36%	0	0	
Midwest Energy, Inc.	6	0.01%		6	0.03%	0	0	
Missouri Public Service & West Plains Energy	1,023	1.36%		1,023	5.21%	27	27	
St. Joseph Light & Power	218	0.29%		218	1.11%	1	1	
Sunflower Electric Power Cooperative	410	0.55%		410	2.09%	4	4	
	12,165	**16.22%**		**12,165**	**61.92%**	**764**	**1,281**	**517**
West Central SPP Region								
Grand River Dam Authority	1,280	1.71%		83	0.42%	0		
KAMO Electric Cooperative	200	0.27%		13	0.07%	0	0	
Northeast Texas Electric Cooperative	117	0.16%		8	0.04%	0		
Oklahoma Gas & Electric	2,530	3.37%		164	0.83%	1		
Oklahoma Municipal Power Authority	118	0.16%		8	0.04%	0		
Central and Southwest	4,345	5.79%		281	1.43%	2		
Southwestern Power Administration	2,079	2.77%		135	0.69%	0		
Southwestern Public Service	300	0.40%		19	0.10%	0		
Western Farmers Electric Cooperative	690	0.92%		45	0.23%	0		
	11,659	**15.55%**	**755**	**755**	**3.84%**	**3**		
South SPP								
Entergy	11,478	15.31%		2,091	10.64%	113		
Arkansas Electric Cooperative	1,473	1.96%		268	1.37%	2		
Central Lousiana Electric Company	922	1.23%		168	0.86%	1		
Southwestern Electric Power	0	0.00%		0	0.00%	0		
City of Alexandria, LA	0	0.00%		0	0.00%	0		
Cajun Electric Power Cooperative	1,393	1.86%		254	1.29%	2		
City of Lafayette, LA	262	0.35%		48	0.24%	0		
City of Clarksdale, MS	0	0.00%		0	0.00%	0		
Louisiana Energy and Power Authority	116	0.15%		21	0.11%	0		
Sam Rayburn G&T	0	0.00%		0	0.00%	0		
	15,644	**20.86%**	**2,850**	**2,850**	**14.51%**	**118**		
MAIN								
Ameren	5,274	7.03%		739	3.76%	14		
Central Illinois Power Cooperative	257	0.34%		36	0.18%	0		
Illinois Power Company	3,743	4.99%		525	2.67%	7		
	9,274	**12.37%**	**1,300**	**1,300**	**6.62%**	**21**		
TVA								
Tennessee Valley Authority	**25,038**	**33.39%**	**1,450**	**1,450**	**7.38%**	**54**		
MAPP								
Cooperative Power	38	0.05%		36	0.18%	0		
IES Utilites	107	0.14%		100	0.51%	0		
Interstate Power Company	36	0.05%		34	0.17%	0		
Lincoln Electric System	0	0.00%		0	0.00%	0		
MidAmerica Energy	232	0.31%		218	1.11%	1		
Minnesota Power	89	0.12%		83	0.42%	0		
Nebraska Public Service	176	0.23%		165	0.84%	1		
Northern States Power	347	0.46%		325	1.66%	3		
Northwestern Public Service	14	0.02%		13	0.07%	0		
Omaha Public Power District	123	0.16%		115	0.59%	0		
Otter Tail Power	38	0.05%		36	0.18%	0		
	1,200	**1.60%**	**1,125**	**1,125**	**5.73%**	**6**		
TOTAL	**74,980**	**100.00%**		**19,645**	**100.00%**	**967**	**1,483**	**517**

* Merger Applicants Case 3: Regional Markets Assuming Zero Transmission Cost Excluding Southern Company

Schedule 4-2

ADJUSTMENTS TO MERGER APPLICANTS SHARES AND CONCENTRATIONS
OF ECONOMIC CAPACITY FOR RELEVANT GEOGRAPHIC MARKET AREA

	Spann*		FCMTC	25 Mills Adjusted for Transmission Import Constraints				
	MW-EC	% Share	TO NORTH	MW-EC	% Share	Pre-HHI	Post-HHI	Change
North SPP Region								31.79%
Kansas City Power & Light	2,631	3.17%		2,631	12.76%	163		
Western Resources	3,923	4.73%		3,923	19.03%	362	1011	
Associated Electric Cooperative	2,502	3.02%		2,502	12.14%	147	147	
Board of Public Utilites - Kansas City, KS	572	0.69%		572	2.77%	8	8	
City of Coffeyville, KS	0	0.00%		0	0.00%	0	0	
City of McPherson, KS	0	0.00%		0	0.00%	0	0	
City of Winfield, KS	40	0.05%		40	0.19%	0	0	
City Utilities - Springfield, MO	651	0.79%		651	3.16%	10	10	
Empire District Electric	677	0.82%		677	3.28%	11	11	
Independence Power & Light	131	0.16%		131	0.64%	0	0	
Kansas Electric Power Cooperative	70	0.08%		70	0.34%	0	0	
Midwest Energy, Inc.	15	0.02%		15	0.07%	0	0	
Missouri Public Service & West Plains Energy	1,252	1.51%		1,252	6.07%	37	37	
St. Joseph Light & Power	260	0.31%		260	1.26%	2	2	
Sunflower Electric Power Cooperative	410	0.49%		410	1.99%	4	4	
	13,134	**15.85%**		**13,134**	**63.71%**	**744**	**1,230**	**486**
West Central SPP Region								
Grand River Dam Authority	1,280	1.54%		71	0.34%	0		
KAMO Electric Cooperative	200	0.24%		11	0.05%	0	0	
Northeast Texas Electric Cooperative	117	0.14%		6	0.03%	0		
Oklahoma Gas & Electric	2,530	3.05%		140	0.68%	0		
Oklahoma Municipal Power Authority	118	0.14%		7	0.03%	0		
Central and Southwest	6,036	7.28%		334	1.62%	3		
Southwestern Power Administration	2,079	2.51%		115	0.56%	0		
Southwestern Public Service	300	0.36%		17	0.08%	0		
Western Farmers Electric Cooperative	969	1.17%		54	0.26%	0		
	13,629	**16.44%**	755	**755**	**3.66%**	**4**		
South SPP								
Entergy	11,902	14.36%		2,056	9.97%	99		
Arkansas Electric Cooperative	1,788	2.16%		309	1.50%	2		
Central Lousiana Electric Company	922	1.11%		159	0.77%	1		
Southwestern Electric Power	0	0.00%		0	0.00%	0		
City of Alexandria, LA	0	0.00%		0	0.00%	0		
Cajun Electric Power Cooperative	1,393	1.68%		241	1.17%	1		
City of Lafayette, LA	262	0.32%		45	0.22%	0		
City of Clarksdale, MS	0	0.00%		0	0.00%	0		
Louisiana Energy and Power Authority	235	0.28%		41	0.20%	0		
Sam Rayburn G&T	0	0.00%		0	0.00%	0		
	16,502	**19.91%**	2,850	**2,850**	**13.83%**	**104**		
MAIN								
Ameren	7,087	8.55%		689	3.34%	11		
Central Illinois Power Cooperative	2,549	3.08%		248	1.20%	1		
Illinois Power Company	3,743	4.52%		364	1.76%	3		
	13,379	**16.14%**	1,300	**1,300**	**6.31%**	**16**		
TVA								
Tennessee Valley Authority	**25,038**	**30.21%**	1,450	**1,450**	**7.03%**	**49**		
MAPP								
Cooperative Power	36	0.04%		34	0.16%	0		
IES Utilites	106	0.13%		99	0.48%	0		
Interstate Power Company	41	0.05%		38	0.19%	0		
Lincoln Electric System	5	0.01%		5	0.02%	0		
MidAmerica Energy	233	0.28%		218	1.06%	1		
Minnesota Power	86	0.10%		81	0.39%	0		
Nebraska Public Service	174	0.21%		163	0.79%	1		
Northern States Power	351	0.42%		329	1.59%	3		
Northwestern Public Service	14	0.02%		13	0.06%	0		
Omaha Public Power District	118	0.14%		111	0.54%	0		
Otter Tail Power	37	0.04%		35	0.17%	0		
	1,201	**1.45%**	1,125	**1,125**	**5.46%**	**5**		
TOTAL	**82,883**	**100.00%**		**20,614**	**100.00%**	**921**	**1,407**	**486**

* Merger Applicants Case 3: Regional Markets Assuming Zero Transmission Cost
Excluding Southern Company

ADJUSTMENTS TO MERGER APPLICANTS SHARES AND CONCENTRATIONS OF ECONOMIC CAPACITY FOR RELEVANT GEOGRAPHIC MARKET AREA

	Spann*		FCMTC	35 Mills Adjusted for Transmission Import Constraints				
	MW-EC	% Share	TO NORTH	MW-EC	% Share	Pre-HHI	Post-HHI	Change
North SPP Region								35.12%
Kansas City Power & Light	2,705	2.75%		2,705	12.01%	144		
Western Resources	5,202	5.28%		5,202	23.10%	534	1233	
Associated Electric Cooperative	2,502	2.54%		2,502	11.11%	123	123	
Board of Public Utilites - Kansas City, KS	572	0.58%		572	2.54%	6	6	
City of Coffeyville, KS	56	0.06%		56	0.25%	0	0	
City of McPherson, KS	182	0.18%		182	0.81%	1	1	
City of Winfield, KS	52	0.05%		52	0.23%	0	0	
City Utilities - Springfield, MO	651	0.66%		651	2.89%	8	8	
Empire District Electric	710	0.72%		710	3.15%	10	10	
Independence Power & Light	170	0.17%		170	0.75%	1	1	
Kansas Electric Power Cooperative	70	0.07%		70	0.31%	0	0	
Midwest Energy, Inc.	28	0.03%		28	0.12%	0	0	
Missouri Public Service & West Plains Energy	1,355	1.38%		1,355	6.02%	36	36	
St. Joseph Light & Power	260	0.26%		260	1.15%	1	1	
Sunflower Electric Power Cooperative	522	0.53%		522	2.32%	5	5	
	15,037	**15.27%**		**15,037**	**66.78%**	**871**	**1,426**	**555**
West Central SPP Region								
Grand River Dam Authority	1,280	1.30%		58	0.26%	0		
KAMO Electric Cooperative	200	0.20%		9	0.04%	0		
Northeast Texas Electric Cooperative	117	0.12%		5	0.02%	0		
Oklahoma Gas & Electric	2,530	2.57%		115	0.51%	0		
Oklahoma Municipal Power Authority	118	0.12%		5	0.02%	0		
Central and Southwest	8,824	8.96%		403	1.79%	3		
Southwestern Power Administration	2,079	2.11%		95	0.42%	0		
Southwestern Public Service	300	0.30%		14	0.06%	0		
Western Farmers Electric Cooperative	1,093	1.11%		50	0.22%	0		
	16,541	**16.80%**	**755**	**755**	**3.35%**	**4**		
South SPP								
Entergy	20,156	20.47%		2,116	9.40%	88		
Arkansas Electric Cooperative	1,788	1.82%		188	0.83%	1		
Central Lousiana Electric Company	2,633	2.67%		276	1.23%	2		
Southwestern Electric Power	0	0.00%		0	0.00%	0		
City of Alexandria	0	0.00%		0	0.00%	0		
Cajun Electric Power Cooperative	1,613	1.64%		169	0.75%	1		
City of Lafayette, LA	580	0.59%		61	0.27%	0		
City of Clarksdale, MS	23	0.02%		2	0.01%	0		
Louisiana Energy and Power Authority	350	0.36%		37	0.16%	0		
Sam Rayburn G&T	0	0.00%		0	0.00%	0		
	27,143	**27.57%**	**2,850**	**2,850**	**12.66%**	**91**		
MAIN								
Ameren	7,087	7.20%		682	3.03%	9		
Central Illinois Power Cooperative	2,673	2.71%		257	1.14%	1		
Illinois Power Company	3,743	3.80%		360	1.60%	3		
	13,503	**13.71%**	**1,300**	**1,300**	**5.77%**	**13**		
TVA								
Tennessee Valley Authority	**25,038**	**25.43%**	**1,450**	**1,450**	**6.44%**	**41**		
MAPP								
Cooperative Power	35	0.04%		33	0.15%	0		
IES Utilites	101	0.10%		95	0.42%	0		
Interstate Power Company	59	0.06%		55	0.25%	0		
Lincoln Electric System	5	0.01%		5	0.02%	0		
MidAmerica Energy	247	0.25%		231	1.03%	1		
Minnesota Power	82	0.08%		77	0.34%	0		
Nebraska Public Service	166	0.17%		155	0.69%	0		
Northern States Power	338	0.34%		316	1.40%	2		
Northwestern Public Service	13	0.01%		12	0.05%	0		
Omaha Public Power District	120	0.12%		112	0.50%	0		
Otter Tail Power	36	0.04%		34	0.15%	0		
	1,202	**1.22%**	**1,125**	**1,125**	**5.00%**	**4**		
TOTAL	**98,464**	**100.00%**	**7,480**	**22,517**	**100.00%**	**1,024**	**1,579**	**555**

* Merger Applicants Case 3: Regional Markets Assuming Zero Transmission Cost Excluding Southern Company

ENTERGY AS A DESTINATION MARKET
ECONOMIC CAPACITY

	Spann*		FCMTC	14 Mills Adjusted for Transmission Import Constraints				
	MW-EC	% Share	TO SOUTH	MW-EC	% Share	Pre-HHI	Post-HHI	Change
North SPP Region								2.69%
Kansas City Power & Light	2,631	6.01%		132	1.11%	1		
Western Resources	3,734	8.53%		188	1.58%	2	7	
Associated Electric Cooperative	2,280	5.21%		115	0.96%	1	1	
Board of Public Utilites - Kansas City, KS	290	0.66%		15	0.12%	0	0	
City of Coffeyville, KS	0	0.00%		0	0.00%	0		
City of McPherson, KS	0	0.00%		0	0.00%	0	0	
City of Winfield, KS	0	0.00%		0	0.00%	0	0	
City Utilities - Springfield, MO	178	0.41%		9	0.08%	0	0	
Empire District Electric	307	0.70%		15	0.13%	0	0	
Independence Power & Light	93	0.21%		5	0.04%	0	0	
Kansas Electric Power Cooperative	70	0.16%		4	0.03%	0	0	
Midwest Energy, Inc.	0	0.00%		0	0.00%	0	0	
Missouri Public Service & West Plains Energy	909	2.08%		46	0.38%	0	0	
St. Joseph Light & Power	121	0.28%		6	0.05%	0	0	
Sunflower Electric Power Cooperative	325	0.74%		16	0.14%	0	0	
	10,938	**24.99%**	**550**	**550**	**4.63%**	**5**	**8**	**4**
West Central SPP Region								
Grand River Dam Authority	1,280	2.92%		276	2.32%	5		
KAMO Electric Cooperative	200	0.46%		43	0.36%	0	0	
Northeast Texas Electric Cooperative	78	0.18%		17	0.14%	0		
Oklahoma Gas & Electric	2,530	5.78%		545	4.58%	21		
Oklahoma Municipal Power Authority	118	0.27%		25	0.21%	0		
Central and Southwest	2,502	5.72%		539	4.53%	21		
Southwestern Power Administration	2,079	4.75%		448	3.77%	14		
Southwestern Public Service	39	0.09%		8	0.07%	0		
Western Farmers Electric Cooperative	0	0.00%		0	0.00%	0		
	8,826	**20.17%**	**1,900**	**1,900**	**15.99%**	**35**		
South SPP								
Entergy	3,575	8.17%		3,575	30.08%	905		
Arkansas Electric Cooperative	65	0.15%		65	0.55%	0		
Central Lousiana Electric Company	0	0.00%		0	0.00%	0		
Southwestern Electric Power	0	0.00%		0	0.00%	0		
City of Alexandria, LA	0	0.00%		0	0.00%	0		
Cajun Electric Power Cooperative	0	0.00%		0	0.00%	0		
City of Lafayette	0	0.00%		0	0.00%	0		
City of Clarksdale, MS	0	0.00%		0	0.00%	0		
Louisiana Energy and Power Authority	0	0.00%		0	0.00%	0		
Sam Rayburn G&T	0	0.00%		0	0.00%	0		
	3,640	**8.32%**		**3,640**	**30.63%**	**905**		
MAIN								
Ameren	1,812	4.14%		644	5.42%	29		
Central Illinois Power Cooperative	0	0.00%		0	0.00%	0		
Illinois Power Company	2,198	5.02%		781	6.57%	43		
	4,010	**9.16%**	**1,425**	**1,425**	**11.99%**	**73**		
SERC - TVA								
Tennessee Valley Authority	**10,353**	**23.65%**	**2,868**	**2,868**	**24.13%**	**582**		
SERC - SOUTHERN								
Southern Company	**6,001**	**13.71%**	**1,501**	**1,501**	**12.63%**	**160**		
TOTAL	**43,768**	**100.00%**		**11,884**	**100.00%**	**1,759**	**1,763**	**4**

* Merger Applicants Case 3: Regional Markets Assuming Zero Transmission Cost
Exlcuding MAPP and Including Southern Company

ENTERGY AS A DESTINATION MARKET
ECONOMIC CAPACITY

	Spann*		FCMTC	20 Mills Adjusted for Transmission Import Constraints				
	MW-EC	% Share	TO SOUTH	MW-EC	% Share	Pre-HHI	Post-HHI	Change
North SPP Region								1.22%
Kansas City Power & Light	2,631	2.91%		119	0.50%	0		
Western Resources	3,790	4.19%		171	0.72%	1	1	
Associated Electric Cooperative	2,502	2.76%		113	0.47%	0	0	
Board of Public Utilites - Kansas City, KS	572	0.63%		26	0.11%	0	0	
City of Coffeyville, KS	0	0.00%		0	0.00%	0	0	
City of McPherson, KS	0	0.00%		0	0.00%	0	0	
City of Winfield, KS	0	0.00%		0	0.00%	0	0	
City Utilities - Springfield, MO	413	0.46%		19	0.08%	0	0	
Empire District Electric	399	0.44%		18	0.08%	0	0	
Independence Power & Light	131	0.14%		6	0.02%	0	0	
Kansas Electric Power Cooperative	70	0.08%		3	0.01%	0	0	
Midwest Energy, Inc.	6	0.01%		0	0.00%	0	0	
Missouri Public Service & West Plains Energy	1,023	1.13%		46	0.19%	0	0	
St. Joseph Light & Power	218	0.24%		10	0.04%	0	0	
Sunflower Electric Power Cooperative	410	0.45%		19	0.08%	0	0	
	12,165	**13.43%**	**550**	**550**	**2.30%**	**1**	**2**	**1**
West Central SPP Region								
Grand River Dam Authority	1,280	1.41%		209	0.87%	1		
KAMO Electric Cooperative	200	0.22%		33	0.14%	0	0	
Northeast Texas Electric Cooperative	117	0.13%		19	0.08%	0		
Oklahoma Gas & Electric	2,530	2.79%		412	1.73%	3		
Oklahoma Municipal Power Authority	118	0.13%		19	0.08%	0		
Central and Southwest	4,345	4.80%		708	2.96%	9		
Southwestern Power Administration	2,079	2.30%		339	1.42%	2		
Southwestern Public Service	300	0.33%		49	0.20%	0		
Western Farmers Electric Cooperative	690	0.76%		112	0.47%	0		
	11,659	**12.87%**	**1,900**	**1,900**	**7.95%**	**15**		
South SPP								
Entergy	11,478	12.67%		11,478	48.05%	2,309		
Arkansas Electric Cooperative	1,473	1.63%		1,473	6.17%	38		
Central Lousiana Electric Company	922	1.02%		922	3.86%	15		
Southwestern Electric Power	0	0.00%		0	0.00%	0		
City of Alexandria, LA	0	0.00%		0	0.00%	0		
Cajun Electric Power Cooperative	1,393	1.54%		1,393	5.83%	34		
City of Lafayette, LA	262	0.29%		262	1.10%	1		
City of Clarksdale, MS	0	0.00%		0	0.00%	0		
Louisiana Energy and Power Authority	116	0.13%		116	0.49%	0		
Sam Rayburn G&T	0	0.00%		0	0.00%	0		
	15,644	**17.27%**		**15,644**	**65.49%**	**2,397**		
MAIN								
Ameren	5,274	5.82%		810	3.39%	12		
Central Illinois Power Cooperative	257	0.28%		39	0.17%	0		
Illinois Power Company	3,743	4.13%		575	2.41%	6		
	9,274	**10.24%**	**1,425**	**1,425**	**5.97%**	**17**		
SERC - TVA								
Tennessee Valley Authority	**25,038**	**27.65%**	**2,868**	**2,868**	**12.01%**	**144**		
SERC - SOUTHERN								
Southern Company	**16,780**	**18.53%**	**1,501**	**1,501**	**6.28%**	**39**		
TOTAL	**90,560**	**100.00%**		**23,888**	**100.00%**	**2,614**	**2,615**	**1**

* Merger Applicants Case 3: Regional Markets Assuming Zero Transmission Cost
Excluding MAPP and Including Southern Company

ENTERGY AS A DESTINATION MARKET
ECONOMIC CAPACITY

	Spann*		FCMTC	25 Mills Adjusted for Transmission Import Constraints				
	MW-EC	% Share	TO SOUTH	MW-EC	% Share	Pre-HHI	Post-HHI	Change
North SPP Region								**1.11%**
Kansas City Power & Light	2,631	2.45%		110	0.45%	0		
Western Resources	3,923	3.66%		164	0.66%	0	1	
Associated Electric Cooperative	2,502	2.33%		105	0.42%	0	0	
Board of Public Utilites - Kansas City, KS	572	0.53%		24	0.10%	0	0	
City of Coffeyville, KS	0	0.00%		0	0.00%	0	0	
City of McPherson, KS	0	0.00%		0	0.00%	0	0	
City of Winfield, KS	40	0.04%		2	0.01%	0	0	
City Utilities - Springfield, MO	651	0.61%		27	0.11%	0	0	
Empire District Electric	677	0.63%		28	0.11%	0	0	
Independence Power & Light	131	0.12%		5	0.02%	0	0	
Kansas Electric Power Cooperative	70	0.07%		3	0.01%	0	0	
Midwest Energy, Inc.	15	0.01%		1	0.00%	0	0	
Missouri Public Service & West Plains Energy	1,252	1.17%		52	0.21%	0	0	
St. Joseph Light & Power	260	0.24%		11	0.04%	0	0	
Sunflower Electric Power Cooperative	410	0.38%		17	0.07%	0	0	
	13,134	**12.25%**	**550**	**550**	**2.22%**	**1**	**1**	**1**
West Central SPP Region								
Grand River Dam Authority	1,280	1.19%		178	0.72%	1		
KAMO Electric Cooperative	200	0.19%		28	0.11%	0	0	
Northeast Texas Electric Cooperative	117	0.11%		16	0.07%	0		
Oklahoma Gas & Electric	2,530	2.36%		353	1.43%	2		
Oklahoma Municipal Power Authority	118	0.11%		16	0.07%	0		
Central and Southwest	6,036	5.63%		841	3.40%	12		
Southwestern Power Administration	2,079	1.94%		290	1.17%	1		
Southwestern Public Service	300	0.28%		42	0.17%	0		
Western Farmers Electric Cooperative	969	0.90%		135	0.55%	0		
	13,629	**12.72%**	**1,900**	**1,900**	**7.68%**	**16**		
South SPP								
Entergy	11,902	11.10%		11,902	48.10%	2,313		
Arkansas Electric Cooperative	1,788	1.67%		1,788	7.23%	52		
Central Lousiana Electric Company	922	0.86%		922	3.73%	14		
Southwestern Electric Power	0	0.00%		0	0.00%	0		
City of Alexandria, LA	0	0.00%		0	0.00%	0		
Cajun Electric Power Cooperative	1,393	1.30%		1,393	5.63%	32		
City of Lafayette, LA	262	0.24%		262	1.06%	1		
City of Clarksdale, MS	0	0.00%		0	0.00%	0		
Louisiana Energy and Power Authority	235	0.22%		235	0.95%	1		
Sam Rayburn G&T	0	0.00%		0	0.00%	0		
	16,502	**15.40%**		**16,502**	**66.69%**	**2,413**		
MAIN								
Ameren	7,087	6.61%		755	3.05%	9		
Central Illinois Power Cooperative	2,549	2.38%		271	1.10%	1		
Illinois Power Company	3,743	3.49%		399	1.61%	3		
	13,379	**12.48%**	**1,425**	**1,425**	**5.76%**	**13**		
SERC - TVA								
Tennessee Valley Authority	**25,038**	**23.36%**	**2,868**	**2,868**	**11.59%**	**134**		
SERC - SOUTHERN								
Southern Company	**25,499**	**23.79%**	**1,501**	**1,501**	**6.07%**	**37**		
TOTAL	**107,181**	**100.00%**		**24,746**	**100.00%**	**2,614**	**2,615**	**1**

* Merger Applicants Case 3: Regional Markets Assuming Zero Transmission Cost
Excluding MAPP and Including Southern Company

Schedule 5-3

ENTERGY AS A DESTINATION MARKET
ECONOMIC CAPACITY

	Spann*		FCMTC	35 Mills Adjusted for Transmission Import Constraints				
	MW-EC	% Share	TO SOUTH	MW-EC	% Share	Pre-HHI	Post-HHI	Change
North SPP Region								0.82%
Kansas City Power & Light	2,705	2.16%		99	0.28%	0		
Western Resources	5,202	4.15%		190	0.54%	0	1	
Associated Electric Cooperative	2,502	2.00%		92	0.26%	0	0	
Board of Public Utilites - Kansas City, KS	572	0.46%		21	0.06%	0	0	
City of Coffeyville, KS	56	0.04%		2	0.01%	0	0	
City of McPherson, KS	182	0.15%		7	0.02%	0	0	
City of Winfield, KS	52	0.04%		2	0.01%	0	0	
City Utilities - Springfield, MO	651	0.52%		24	0.07%	0	0	
Empire District Electric	710	0.57%		26	0.07%	0	0	
Independence Power & Light	170	0.14%		6	0.02%	0	0	
Kansas Electric Power Cooperative	70	0.06%		3	0.01%	0	0	
Midwest Energy, Inc.	28	0.02%		1	0.00%	0	0	
Missouri Public Service & West Plains Energy	1,355	1.08%		50	0.14%	0	0	
St. Joseph Light & Power	260	0.21%		10	0.03%	0	0	
Sunflower Electric Power Cooperative	522	0.42%		19	0.05%	0	0	
	15,037	**12.00%**	**550**	**550**	**1.55%**	**0**	**1**	**0**
West Central SPP Region								
Grand River Dam Authority	1,280	1.02%		147	0.42%	0		
KAMO Electric Cooperative	200	0.16%		23	0.06%	0		
Northeast Texas Electric Cooperative	117	0.09%		13	0.04%	0		
Oklahoma Gas & Electric	2,530	2.02%		291	0.82%	1		
Oklahoma Municipal Power Authority	118	0.09%		14	0.04%	0		
Central and Southwest	8,824	7.04%		1,014	2.86%	8		
Southwestern Power Administration	2,079	1.66%		239	0.67%	0		
Southwestern Public Service	300	0.24%		34	0.10%	0		
Western Farmers Electric Cooperative	1,093	0.87%		126	0.35%	0		
	16,541	**13.20%**	**1,900**	**1,900**	**5.37%**	**10**		
South SPP								
Entergy	20,156	16.09%		20,156	56.96%	3,244		
Arkansas Electric Cooperative	1,788	1.43%		1,788	5.05%	26		
Central Lousiana Electric Company	2,633	2.10%		2,633	7.44%	55		
Southwestern Electric Power	0	0.00%		0	0.00%	0		
City of Alexandria	0	0.00%		0	0.00%	0		
Cajun Electric Power Cooperative	1,613	1.29%		1,613	4.56%	21		
City of Lafayette, LA	580	0.46%		580	1.64%	3		
City of Clarksdale, MS	23	0.02%		23	0.06%	0		
Louisiana Energy and Power Authority	350	0.28%		350	0.99%	1		
Sam Rayburn G&T	0	0.00%		0	0.00%	0		
	27,143	**21.66%**		**27,143**	**76.70%**	**3,350**		
MAIN								
Ameren	7,087	5.66%		748	2.11%	4		
Central Illinois Power Cooperative	2,673	2.13%		282	0.80%	1		
Illinois Power Company	3,743	2.99%		395	1.12%	1		
	13,503	**10.78%**	**1,425**	**1,425**	**4.03%**	**6**		
SERC - TVA								
Tennessee Valley Authority	**25,038**	**19.98%**	**2,868**	**2,868**	**8.10%**	**66**		
SERC - SOUTHERN								
Southern Company	**28,035**	**22.37%**	**1,501**	**1,501**	**4.24%**	**18**		
TOTAL	**125,297**	**100.00%**	**7,694**	**35,387**	**100.00%**	**3,450**	**3,450**	**0**

* Merger Applicants Case 3: Regional Markets Assuming Zero Transmission Cost
Excluding MAPP and Including Southern Company