AEP Exhibit No. 5

IN THE UNITED STATES OF AMERICA

BEFORE THE

SECURITIES AND EXCHANGE COMMISSION

In the Matter of American Electric Power Company, Inc.: File No. 3-11616

PREPARED DIRECT TESTIMONY OF
J. CRAIG BAKER
ON BEHALF OF
THE AMERICAN ELECTRIC POWER SYSTEM

December 7, 2004

PREPARED DIRECT TESTIMONY

J. CRAIG BAKER

SEC ADMIN PROCEEDING

FILE NO. 3-11616

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND CURRENT POSITION.

A. My name is J. Craig Baker. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am Senior Vice President-Regulatory Services, for American Electric Power Service Corporation ("AEPSC"). AEPSC provides professional services to the companies of the American Electric Power (AEP) System.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor's Degree in Business Administration from Walsh College in 1970 and a Masters Degree in Business Administration in Finance from Akron University in 1980. I joined the AEP System in 1968 and through 1979 held various positions in the Computer Applications Division. I transferred to the System Operation Division in 1979 and held positions of Administrative Assistant and Assistant Manager. In 1985, I took the position of Staff Analyst in the Controllers Department and, in 1987, I became Manager-Power Marketing in the System Power Markets Department. In 1991, I became Director, Interconnection Agreements and Marketing. I became Vice President-Power Marketing for AEPSC and Senior Vice President of Energy Marketing for AEP Energy Services, Inc. in November 1996 and August 1997, respectively. On July 1, 1998 I became Vice President of Transmission Policy for AEPSC. In June 2000, I became Senior Vice President of Public Policy for AEPSC. In 2001, I assumed my current position.

Q. PLEASE DESCRIBE YOUR DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION.

A. I am responsible for AEP's activities before eleven state regulatory commissions and the Federal Energy Regulatory Commission ("FERC"). A major focus of my activities since 1998 has been AEP's participation in regional transmission organizations ("RTOs") including AEP's planned participation in the Alliance RTO, and, more recently, in PJM Interconnection, L.L.C. ("PJM") and the Southwest Power Pool RTO.

II. <u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide evidence that will assist the Commission in supporting its findings that the combined AEP System meets the Interconnection and Single Area or Region requirements of an integrated public utility system under the Public Utility Holding Company Act of 1935 ("PUHCA").

III. <u>BACKGROUND</u>

Q. PLEASE BRIEFLY REVIEW THE BACKGROUND EVENTS LEADING TO YOUR TESTIMONY?

A. In late 1997, the AEP System and the Central and South West System ("CSW") agreed to merge, subject to receiving required regulatory approvals. AEP was a multistate electric utility holding company system registered with the Commission under PUHCA. AEP's seven operating companies, provided electric service to about 3 million customers in parts of Indiana, Michigan, Ohio, Kentucky, Virginia, West Virginia and Tennessee. CSW was also a registered integrated holding company system registered with the Commission under PUHCA. Its four operating companies served about 1.7 million customers in parts of Arkansas, Louisiana, Oklahoma and Texas.

When I speak of the post-merger AEP system in my testimony, I will sometimes use the term “combined system.” When I speak of the pre-merger AEP system, I will sometimes use the term “east zone” and for the former CSW system the “west zone.”

The merger required regulatory approvals, the most important being approvals by the Federal Energy Regulatory Commission (“FERC”), various regulatory commissions in the states where the combined system’s operating companies provide service, and, of course, this Commission.

The FERC and various state regulatory commissions conducted a thorough review of the proposed merger. FERC, in particular, held hearings and examined in detail the effect of the merger on competition, customers’ rates and regulation. In 2000, FERC approved the merger, subject to certain conditions which have been fulfilled. FERC’s approval of the merger has been upheld by the court of appeals. The required state approvals were also obtained.

This Commission also approved the merger, finding, as had the FERC and state commissions, that the combination would result in cost savings of approximately 2 billion dollars. AEP and the former CSW have been successfully operating on a merged basis since 2000. In many of AEP’s jurisdictions, approvals have resulted in a sharing of the projected merger benefits, so hundreds of millions of dollars in benefits have been passed back to customers.

This Commission's approval of the merger was appealed by two associations of cooperatively-owned and publicly-owned utilities, respectively. In 2002, the United States Court of Appeals for the District of Columbia ("Appeals Court" or "Court") reversed the Commission's approval and remanded the case to this Commission for further proceedings. As I understand it, the Court upheld many of the Commission's findings, but held that the Commission had not adequately explained or supported its findings that (1) the combined system is "physically interconnected or capable of physical interconnection" ("the Interconnection Requirement") and (2) that the combined system is "confined to a single area or region" ("the Region Requirement.")

I will address each of these requirements in detail. First, however, I will discuss some basic concepts concerning the electric utility industry - - particularly the economic and reliability advantages of interconnection and coordination of electric utilities. An explanation of these basic concepts will help the reader better to understand the remainder of my testimony.

Q. PLEASE PROVIDE A SIMPLE EXPLANATION OF HOW ELECTRIC UTILITIES CAN ACHIEVE EFFICIENCIES AND ECONOMIES THROUGH SYSTEM INTERCONNECTION AND INTEGRATION.

A. Let's start with a simple example. Suppose two electric utility companies, Able and Baker (no relation) are operating in proximity, but are not connected, to one another. Each owns one coal-fired generating plant of about the same size -- say five hundred megawatts ("MW") (a MW is a million watts). However, Able Company is located in an area of the state where the economy is booming, and its customers' demand for electricity during peak hours has risen to 400 MW and is expected to continue to increase. Able knows it will soon be running out of resources to serve its customers. Reliability rules, designed to keep the lights on under reasonable contingencies, demand that utilities carry an amount of reserve generating capacity above their expected peak. In this instance, assume the reserve margin is 15%, or in Able's case, 60 MW. With 500 MW of capacity, Able is just barely meeting reserve requirements, and must acquire new resources to meet imminent load growth. Building a new power plant, though, will be very costly.

The economy in Baker Company's service territory, on the other hand, has not been faring very well. There have been some major industrial plant closings, and people are moving to Able Company's part of the state to pursue better opportunities. Baker Company has plenty of available generating capacity – 500 MW to serve its peak load of 250 MW. And its customers are paying for this unused capacity – a fact not conducive to turning the corner on economic development in Baker's area.

Able Company and Baker Company agree on a win-win solution. Each extends one or more of its transmission lines and they connect to one another, so that power can be transferred between them. This is cheaper for Able than building a new power plant, and it enables Baker to sell off some of its excess generating capacity, thus reducing the cost burden on its own customers. Thus, interconnection and coordination (in this case, transferring power) between these two utilities has achieved two obvious economic benefits:

1) Able has avoided the cost of building a new power plant; and

2) Baker can better utilize its existing generating capacity.

But there are additional, perhaps less obvious, benefits. Interconnection and coordination also provide each company with increased support in case of emergencies, since available power from one company can be transmitted to the other when needed. For this reason, the reserve margin necessary to cover emergencies can be lowered. Electric utilities that are connected to one another can afford to carry lower reserves than if they were isolated, because of the possibility of support from their interconnected neighbors. Finally, operating economies can be achieved given differences in costs and load characteristics.

Q. PLEASE GIVE AN EXAMPLE OF OPERATING EFFICIENCIES ACHIEVABLE THROUGH INTERCONNECTION AND COORDINATION.

A. Using our very simple example, suppose that Able Company's managers, although lucky for being in a high-growth area, were unlucky in that the operating costs of their plant are very high. Baker's plant, on the other hand, is less costly to operate. This could occur for any number of reasons. For example, Baker's plant could be located on a navigable river with low cost fuel transportation options. Because of these cost differences, Baker can sell Able available electric energy not only to serve new load growth on Able's system as discussed earlier, but also to allow Able to reduce the output of its own expensive-to-operate generation and rely on cheaper purchased power from Baker to meet its requirements. Operating economies can also be achieved from differences in demand profiles. For example, companies that experience their peak loads at different times can take advantage of this diversity by obtaining power from the system that is not experiencing its peak to achieve optimum operations.

Because of the efficiencies and economies associated with interconnection and coordination among electric utilities, as illustrated in the simple examples discussed above, the trend in the electric industry, almost from its inception, has been toward continually increasing interconnection and coordination among utilities. My testimony in section IV, below, and the testimony of AEP witness Paul B. Johnson, will discuss these trends in detail.

Q. YOU HAVE DISCUSSED INTERCONNECTION AND COORDINATION OF ELECTRIC UTILITIES. WOULD YOU PLEASE DISCUSS INTEGRATION?

A. Yes. There are many possible arrangements by which electric utilities can achieve the benefits of interconnection and coordination. The agreement to interconnect and to make mutually beneficial power transfers described in the above example is probably the most basic form. A more sophisticated form of interconnection and coordination arrangement is the "power pool" in which multiple non-affiliated utilities agree to coordinate the planning and operation of their power supply and delivery facilities. An example of a power pool is the Southwest Power Pool ("SPP") located in the central southwest portion of the United States. Power pools can achieve even greater efficiency by becoming "tight" pools. A tight pool is a group of non-affiliated companies that agree to have their facilities centrally planned and operated by an agent. Tight power pools took hold in the eastern United States, and include the Pennsylvania-New Jersey-Maryland Interconnection ("PJM"), the New York Power Pool ("NYPP") and the New England Power Pool ("NEPOOL").

The purest form of electric utility interconnection and coordination, however, is system integration where two or more electric utilities are under common ownership and are planned and operated as a single unit. In our example, if Able and Baker Companies were commonly owned, they could have been planned and operated from the beginning to achieve even greater economies and efficiencies than they achieved through their interconnection agreement. Electric utility holding companies can achieve the benefits of integration for their member operating companies and their customers.

My lay understanding of the interconnection and integration requirements of PUHCA is that they are meant to preserve the benefits available through commonly-owned electric utilities that plan and operate their systems as a single interconnected and coordinated whole. This brings me to the discussion of the Interconnection Requirement.

IV. INTERCONNECTION REQUIREMENT

Q. IS THE COMBINED AEP SYSTEM OPERATED AS A SINGLE INTERCONNECTED AND COORDINATED WHOLE?

A. Yes it is.

Q. HOW ARE THE TWO PARTS OF THE SYSTEM (THE EAST ZONE AND THE WEST ZONE) INTERCONNECTED?

A. They are interconnected by using transmission service contracts to move electric power and energy across the system of Ameren Corporation, a non-affiliated utility, pursuant to an Open Access Transmission Tariff ("OATT"). AEP's rights under the OATT are sufficient to allow the system to be operated as a single interconnected and coordinated whole.

Q. WHAT HAVE YOU BEEN ASKED TO ADDRESS WITH RESPECT TO THIS MANNER OF INTERCONNECTION?

A. Counsel have asked me to address the following language from the January 18, 2002 Appeals Court's Opinion:

> We are, however, puzzled by the Commission's acceptance of a unidirectional contract path to "interconnect" AEP and CSW. Webster's Dictionary defines "interconnection" as "connection

> between two or more: *mutual* connection" -- a definition that seems, on its face, to require two-way transfers of power. WEBSTER'S THIRD NEW INTERNATIONAL DICTIONARY 1177 (1993) (emphasis added). In addition, PUHCA itself requires that the interconnected system be one "which under normal conditions may be economically operated as a single interconnected and coordinated" whole. *15 U.S.C. § 79b*(a)(29)(A). Absent some explanation from the Commission, we cannot understand how a system restricted to unidirectional flow of power from one half to the other can be operated in such a manner.

First, I will clear up the court's apparent misconception that AEP uses a "unidirectional contract path" for the interconnection, and that the system is "restricted to unidirectional flow of power from one half to the other." Then I will provide a full explanation of how AEP effectively uses open access transmission service to achieve system integration.

Q. DOES AEP HAVE ONLY A UNIDIRECTIONAL CONTRACT PATH ACROSS AMEREN?

A. No it does not. AEP has a contract for firm transmission service that it uses to move electric power and energy across Ameren's system. For transfers from east to west, AEP has reserved a contract path of 250 MW under its firm transmission contract. However, AEP has the right under applicable FERC rules, to redirect its contract path from west to east at any time at no additional charge. In addition, for east to west transfers in addition to those using the firm path, and for west to east transfers, AEP can purchase non-firm transmission service from Ameren. Perhaps the fact that AEP has only reserved *firm* transmission service from east to west led the court mistakenly to believe that AEP has only a unidirectional contract path across Ameren and that the flow of power under

AEP's contract is restricted to a unidirectional flow of power. In fact, AEP's contract rights can be, and are, used to move power in both directions.

Q. PLEASE EXPLAIN HOW AEP USES FIRM AND NON-FIRM TRANSMISSION SERVICE RIGHTS TO INTEGRATE ITS SYTEM.

A. An understanding of how transmission service can be used to achieve system integration must start with a basic understanding of FERC Order No. 888. This revolutionary order, issued by the FERC in 1996, has greatly facilitated the use of transmission contract rights, in lieu of ownership of transmission facilities, in achieving electric system interconnection and integration.

Q. HOW DID FERC ORDER NO. 888 CHANGE THE ELECTRIC UTILITY INDUSTRY?

A. Prior to Order No. 888, electric utilities used their transmission lines to serve their own customers and to make off-system wholesale sales, and may have allowed third parties to transmit (or "wheel") power across their systems at their discretion or under a cumbersome and little-used statutory process that enabled FERC to require utilities to wheel power on a case-by-case basis. Order No. 888 revolutionized the electric utility industry by essentially making transmission-owning utilities common carriers. Order No. 888 requires all electric utilities that own or control transmission facilities to offer transmission service over such facilities, as available, to all eligible parties, such as other utilities, power marketers, independent power producers and even retail customers, in states where customers are allowed to choose their power suppliers. In granting such transmission access, the utility cannot discriminate in favor of its own power sales. So before Order No. 888, a utility seeking to transmit power across another utility's wires essentially had to rely on the good will of the transmitting utility to allow the arrangement to continue. Since Order No. 888, a utility (such as AEP) has a federally-guaranteed right to use the other utility's (such as Ameren's) transmission system so long as capacity is available.

Order No. 888 also implemented a comprehensive regulatory scheme to assure non-discriminatory open access. In a companion order, Order No. 889, FERC required transmission owners to post all information concerning the availability of transmission capability, prices, etc. on an electronic bulletin board called "OASIS" (Open Access Same-time Information System). Order 889 also required functional separation, creating a wall so that a transmitting utility's power merchants have no greater access to transmission information than is available to non-affiliated power merchants through the OASIS. Finally Order No. 888 required each transmitting utility to adopt a pro-forma Open Access Transmission Tariff ("OATT") spelling out in detail standard terms and conditions for transmission service. Utilities can slightly vary the standard terms of the OATT, but only on a showing that the varied terms are equal to or superior to the standard OATT.

Under the FERC standard ("Pro-forma") OATT a transmission provider must offer both firm and non-firm point-to-point transmission service *i.e.*, service from a designated point of receipt ("POR") to a designated point of delivery ("POD"), under standard form contracts.

Q. WHAT IS THE DIFFERENCE BETWEEN FIRM AND NON-FIRM POINT-TO-POINT SERVICE?

A. Firm point-to-point service is the highest priority of service, equal in priority to the utility's use of its own transmission facilities to serve its own "native load" customers, and network transmission service (which allows a customer flexible use of the system to integrate its load and resources located on the transmitting utility's system). Firm customers can change (redirect) their designated points of receipt and/or delivery on either a firm or non-firm basis at no additional cost. For example, a firm east to west transmission reservation by AEP across Ameren can be redirected by AEP to go from west to east. A request to redirect service on a firm basis is treated as a new request, which means it must be reevaluated to see if capacity is available. No such requirement exists to redirect service on a non-firm basis. Finally, long-term firm point-to-point customers (i.e, those holding reservations for a year or more) have a reservation priority to renew ("roll-over") their reservations on expiration, and have a right of first refusal as against competing requests.

Non-firm service is lower in priority than firm service. That is, it can be curtailed before higher priority transactions. A utility does not have to plan its system to provide non-firm service. Non-firm service is also offered in shorter increments than firm service. The shortest available firm service is daily, while non-firm is sold on an hourly basis.

Thus, the FERC OATT provides transmission users considerable flexibility by offering services designed to fit varying needs.

Q. CAN YOU GIVE EXAMPLES OF HOW TRANSMISSION CUSTOMERS CAN USE THE DIFFERENT TYPES OF TRANSMISSION SERVICE TO SERVE DIFFERENT NEEDS?

A. Yes. Firm transmission can be used to lock in transmission rights where there is a need to transfer capacity on a firm basis in order for the receiving party to meet reliability standards, or when the energy cost savings from the transaction are expected to be high and there is a significant risk that capacity may not be available. Since non-firm service is often priced at a discount relative to firm service, and can be purchased for shorter time periods, it can be used to lower costs when the risk of inadequate available capacity is relatively low. For example, a power seller might buy multiple hours of hourly non-firm service to deliver the power, knowing that in some peak hours there is a risk of the transaction being curtailed. The customer may very well be willing to take that risk in return for a discounted rate for non-firm service.

The availability of these products also helps the transmission provider optimize the utilization of its assets. To assure reliability, it is necessary for the transmission provider to be relatively conservative in offering long-term firm service, especially for future periods. It can, and often does occur, however, that in a shorter time horizon, conditions are such that there is unused capacity available. The sale of non-firm service allows the transmission provider to protect reliability both in the long term, because non-firm service can be sold knowing that it can be recalled to protect reliability, and in the short-term, to sell unexpectedly available capacity. In this regard, the sale of transmission service is not unlike many businesses such as airlines and hotels, that charge a premium to lock in availability when it is needed, then discount to fill up empty seats or rooms on a short-term basis.

Q. DID AEP MAKE SUCH BUSINESS JUDGMENTS IN DETERMINING HOW TO USE TRANSMISSION SERVICE OFFERED BY AMEREN TO ACHIEVE INTEGRATION?

A. Yes. An interconnected and coordinated integrated electric system achieves economies by running the lowest cost generating resources available to meet the combined needs of the system, and transferring power as needed to serve those needs. In anticipation of the merger, AEP had performed studies using production cost simulation models. The studies indicated that production cost savings could be achieved primarily by displacing more expensive gas-fired generation in the west zone with less expensive coal-fired generation from the east zone. The production cost models indicated that over a ten-year period, for 87.9 % of the time, power flows would be in the direction of this east to west cost differential. Moreover, the west zone was capacity-short, and the east zone had some available capacity at the time of the merger, which it was expected to be able to commit on a firm basis to the west zone. To assure the availability of transmission service in that direction, AEP made a reservation for long-term (3-year) firm point-to-point transmission service on the Ameren system, which has since been renewed. The production cost models also indicated that in some limited circumstances, west-to-east transfers would be economic. However such transfers were expected to occur with far less frequency than those from east to west -- only 4.3% of the time. It was AEP's judgment, based on its knowledge of electricity markets and public information concerning available transmission capability across the Ameren path, that non-firm service from west to east across Ameren would be available on those few occasions when needed to support such power transfers.

AEP could have reserved long-term firm transmission service from west to east across Ameren, as it had for service in the opposite direction. However, a firm reservation from west to east would have entailed an additional cost of about $3 million per year. Today, the cost would be around $9 million that would be an unnecessary and imprudent expenditure of money, given AEP's right to reverse the path at no additional charge on a firm or non-firm basis and the probability that non-firm service would be available for west to east service. A loose analogy would be buying and paying full price for season sports tickets to accommodate the possibility that your brother may be in town from time-to-time, when the home team is having a losing season, and it is obvious that tickets for individual games could be purchased from a scalper at a fraction of face value.

Q. HAVE ACTUAL OPERATIONS SINCE THE MERGER CONFIRMED THE SOUNDNESS OF THE ECONOMIC ANALYSIS LEADING AEP TO USE FIRM TRANSMISSION SERVICE FOR EAST TO WEST TRANSFERS?

A. Yes. AEP Exhibit No. 6 shows actual energy transferred across the Ameren contract path during the years 2001 to 2004 (through September). The data is illustrated in graphic form on AEP Exhibit No. 7. The two exhibits show, on a monthly basis, transfers from AEP's east zone to its west zone as well as transfers from its west zone to its east zone. As can be seen from the Exhibits, the amount of energy transferred from east to west has averaged about 200,000 megawatt-hours (MWh). By contrast, the transactions from west to east have averaged approximately 4000 MWh or about 2% of the east-to-west transfers. Thus, actual results confirm the production cost simulation projections, made prior to the merger, which indicated that power flows from west to east would constitute only a small fraction of the total power flows. These facts also illustrate the impracticality of paying for a firm west to east path. Spread over the expected usage, the cost of a firm path for west to east transactions would be very high. The unit cost for the approximately 200,000 Mwh of east to west service would be about $4.00 per Mwh while the cost per Mwh for the approximately 4000 Mwh per month of transfer would be $207.00 per Mwh.

Q. **HAS TRANSMISSION CAPACITY BEEN AVAILABLE FOR WEST TO EAST TRANSFERS?**

A. Yes. It is my understanding that there have been no significant problems with obtaining the necessary transmission service.

Q. IS IT LIKELY THAT CAPACITY WILL BE AVAILABLE IN THE FUTURE?

A. Yes. We queried the relevant OASIS bulletin boards for the availability of monthly non-firm service for the two-year period beginning January 1, 2005. Monthly non-firm service was shown as available in 19 of the 24 months reviewed.

Q. DOES THE FACT THAT SOME MONTHS SHOWED MONTHLY NON-FIRM AS UNAVAILABLE INDICATE A POTENTIAL PROBLEM FOR WEST TO EAST POWER TRANSFERS?

A. No. We checked the availability of monthly service for the next two years because daily service is not projected out that far. In fact, however, we would use daily or hourly non-firm service for the relatively few times we will make west to east transfers. Because, as I discussed earlier, long range projections of available capability are likely to be conservative, it is typical that daily service would be available even in future months when no available monthly capacity is projected. Projections for these shorter increments are continually updated as the service time approaches, and as unused reservations are released.

Q. SINCE THE MERGER, HAVE CONDITIONS CHANGED TO MAKE THE AMEREN CONTRACT PATH EVEN MORE USEFUL FOR SYTEM INTEGRATION?

A. Yes. Since the merger, regional transmission organizations ("RTOs") have been formed on both sides of the path. The two RTOs are the Midwest Independent System Operator, Inc. ("MISO") and the Southwest Power Pool RTO ("SPP"). I will discuss RTOs in more detail later in my testimony, but for purposes of the present discussion, it is sufficient to know that an RTO offers transmission service over the combined transmission facilities of a number of utilities that are its transmission-owning members not just over the facilities of a single utility as in the past.

Q. WHAT SIGNIFICANCE DOES THIS HAVE FOR USE OF THE AMEREN CONTRACT PATH FOR SYSTEM INTEGRATION?

A. Utilities use the contract path convention for transmitting electricity. Transactions are scheduled from one "Control Area" to another. AEP witness Paul Johnson explains Control Areas in more detail. The Control Areas historically have corresponded to individual utilities (or holding company systems). Thus, if utility A wants to sell 50 MW of power to utility D, and there are two other utility systems (B and C) located between them, the transaction would be scheduled from A across systems B and C to get to D.

Each control area utility is treated as a single unit for the purpose of transmission contracts. Thus, in our example, there may be multiple actual wire-to-wire connections between any of the utilities in the path, but the contract path is A-B-C-D.

An RTO, though it is made up of a number of utilities, is treated as a single entity for purposes of transmission contracts. So, if A, B and C are in the "ABC" RTO and D is not, the new contract path would be (ABC RTO) – D.

In our case, the existence of the RTOs improves the usefulness of the Ameren contract path, because the wire-to-wire connections between utilities other than Ameren that are in SPP or MISO are available as part of the contract path. Specifically, because Ameren is in the MISO, and Kansas City Power & Light Company, which is interconnected with Ameren, is in SPP (as is PSO), a MISO to SPP contract path is now available. Note also that RTOs charge a single rate for transmission across their systems. The historical practice of charging additive or "pancaked" rates for each control area in the contract path has been eliminated for utilities within an RTO. This makes it cheaper for A to transit power to D (by reducing the number of charges from four to two), and greatly expands electricity markets, as I will discuss later.

Q. WHAT IS THE STATUS OF AEP'S CONTRACT PATH RESERVATION ACROSS AMEREN?

A. The current reservation expires in June, 2005. As indicated in the last answer, now that the individual utilities on both sides of the path are in RTOs, the renewal of the transaction will be handled by the two RTOs involved - -- MISO and SPP. AEP has the right to "roll over" its long-term reservation, and capacity is likely to be available, since it will merely replace the current reservation. AEP will make a formal renewal request in 2005.

Q. ARE THERE CONTRACT PATHS IN ADDITION TO THE AMEREN PATH THAT COULD BE USED TO INTERCONNECT THE TWO PARTS OF THE AEP SYSTEM?

A. Yes. AEP Exhibit No. 8 shows some alternative contract paths that could be used. For example, an alternative contract path would be AEP (PJM) – TVA – Entergy – AEP (SPP). AEP has not pursued these options, because they involve more entities and presumably would be more expensive than the present method of using the Ameren path. However, these alternatives are available as a backup, should either the availability or the economics of the Ameren path change.

V. SINGLE AREA OR REGION REQUIREMENT

Q. WHAT HAVE YOU BEEN ASKED TO ADRESS WITH RESPECT TO THE SINGLE AREA OR REGION REQUIREMENT?

A. PUHCA requires that an integrated utility system be "confined to a single area or region". The Appeals Court reversed the Commission's finding that the AEP/CSW merger meets this requirement "both because the Commission failed to make any evidentiary findings on the issue and because it erroneously concluded that a proposed acquisition that satisfies PUHCA's other requirements also meets the statute's region requirement." I have been asked by counsel to provide evidence that would assist the Commission in correctly finding that the combined AEP System is confined to a single area or region.

Q. WHAT FACTORS DO YOU BELIEVE LEAD TO THE CONCLUSION THAT THE AEP SYSTEM IS CONFINED TO A SINGLE AREA OR REGION?

A. The Court accepted as true the Commission's findings that the terms "area" and "region" are by their very nature susceptible of flexible interpretation, and that recent institutional, legal and technological changes have reduced the relative importance of geographical limitations on utility systems.

I fully agree with the common sense proposition that the question of what constitutes an area or region has considerably evolved as the electric industry has evolved. The clear trend over time has been continually to increase the scope of interaction and trade among the nation's electric utilities. The fundamental drivers for this phenomenon have been the economic and reliability advantages of increased interconnection and coordination as discussed above. These factors, in turn drove technological innovation and increased physical interconnection among electric utilities. At the same time, federal government policy has continually promoted increased interconnection and coordination.

The physical and technological aspects of the trend toward increasing interconnection and coordination are described by AEP Witness Paul Johnson. He describes how in the early days of the electric industry, electric utilities were isolated from one another, and in 1935, when PUHCA was enacted, there was some interconnection and coordination among electric utilities, but not nearly on the scale that exists today. As Mr. Johnson points out, today the Eastern Interconnection operates in continuous synchronism as one big machine. From an electrical standpoint, the Eastern Interconnection can accurately be described as a "single area".

Q. DOES THE COMBINED AEP SYSTEM OPERATE EXCLUSIVELY WITHIN THE EASTERN INTERCONNECTION?

A. No. All of AEP Texas Central Company ("TCC") and most of AEP Texas North Company ("TNC") are situated in ERCOT. However, neither TCC nor TNC can be operated as an independent system without the loss of substantial economies which result from their continued retention by the Combined AEP system. Preliminary estimates indicate lost aggregate economies of more than $50 million if TCC and TNC were no longer part of the Combined AEP system.

Q. HOW HAS FEDERAL POLICY AFFECTED THE ELECTRIC UTILITY INDUSTRY?

Federal policy, at least from the enactment of Part II of the Federal Power Act ("FPA"), which was enacted by Congress in conjunction with PUHCA, has continually encouraged increased interconnection and coordination of the electric industry. In more recent years, although physical interconnection and technological improvements continue, as described by Mr. Johnson, the most significant developments in expansion of the scope of electric utility interaction and trade have come about as a result of federal policy and the resulting institutional, regulatory and legal changes that policy has brought about. In particular, in the last ten years or so, FERC's regulatory policies have greatly accelerated the coordination of electric systems and the expansion of electricity markets. In the following testimony, I will briefly review historical federal policy encouraging interconnection and coordination, and then will discuss in detail the more recent federal policies that have greatly expanded electric utility interaction and markets.

Q. WOULD YOU PROVIDE A BRIEF HISTORY OF FEDERAL ENCOURAGEMENT OF INTERCONNECTION AND COORDINATION OF ELECTRIC FACILITIES?

A. Yes. In 1935 Congress passed both PUHCA and Part II of the FPA. I have already discussed how the integration requirement of PUHCA seeks to preserve the benefits of integrated holding company systems. Part II of the FPA extended federal jurisdiction to the sale at wholesale and transmission of electricity in interstate commerce, and created the Federal Power Commission (now the FERC). Among other things, Part II added section 202 of the FPA, which included language authorizing and directing the FPC to divide the country into regional districts "for the voluntary interconnection and coordination of facilities for the generation, transmission and sale of electric energy…", and went on to provide that "It shall be the duty of the Commission to promote and encourage such interconnection and coordination within each such districts and between such districts." Part II of the FPA was passed in recognition of "The necessity for federal leadership in securing planned coordination of the facilities of the industry which alone can produce an abundance of electricity at the lowest possible costs." (S. Rep. No. 621, 74th Cong., 1st. Sess. 17 (1935).

In 1964, the Federal Power Commission published a landmark "National Power Survey" that chronicled the development of interconnection and coordination in the industry and strongly encouraged an acceleration of the strengthening of interconnected and coordination operations. That was followed closely by the 1965 New York blackout, which led to the development of the National Electric Reliability Council and its reliability councils.

In 1978, in response to the "energy crisis" of the time, Congress passed the Public Utility Regulatory Practices Act ("PURPA"). Among other things, PURPA added several provisions to the FPA, including a provision entitled "pooling". The provision directed FERC and the electric reliability councils to study the opportunities for conservation of energy, optimization in the efficiency of use of facilities and resources and increased reliability through power pooling arrangements. The Commission was authorized to recommend to electric utilities that they voluntarily enter into negotiations where pooling opportunities exist, and empowered the Commission to exempt utilities from any state law or regulation "which prohibits or prevents the voluntary coordination of electric utilities, including any agreement for central dispatch."

PURPA also introduced an element of increased competition into the electric utility industry, which consisted, principally, of vertically-integrated utility systems where a single company owned generation, transmission and distribution facilities and provided electric service to retail customers in franchised service territories. PURPA provided for independent generating companies which would develop cogeneration facilities and small power production facilities. (Cogeneration facilities generate electricity in conjunction with other industrial processes. Small power production facilities are small generators using renewable resources such as wind and water power). PURPA required integrated utilities to purchase power at specified prices from these entities generally known as "qualifying facilities" or "QFs" and to transmit their power. In 1992, Congress enacted the Energy Policy Act, which, among other things, provided further impetus for increased competition in the electric industry. The 1992 Act created a new type of entity, the Exempt Wholesale Generator ("EWG"). EWGs, unlike QFs, can be of any size or technology, but they must only be in the generation, not the transmission or distribution businesses. As their name indicates, they are exempt from many of the regulations applicable to traditional integrated electric utilities. These new independent generators were intended to compete with traditional utilities, thus ultimately lowering costs to consumers. The Act also strengthened provisions in which utilities could be compelled by FERC, on a case-by-case basis, to transmit power for EWGs, or other third parties.

All of these developments led to FERC's pro-competition policy initiatives, beginning in 1996 with Order No. 888. These revolutionary initiatives, which had begun at the time FERC approved the AEP/CSW merger and are reflected in FERC's merger order, have greatly expanded the geographic scope of electricity interaction, institutions and markets.

Q. PLEASE ELABORATE ON FERC'S PRO-COMPETITION POLICY INTIATIVES.

A. FERC's policy initiatives have profoundly affected the nature and structure of the electric utility industry, transforming it from an industry primarily focused on the provision of local utility service, to one of increasingly expanding interstate markets and associated institutions. These initiatives have been continuously pursued by the FERC since the mid 1990s; however, they can roughly be divided into three stages: (1) open transmission access; (2) development of RTOs and (3) standard market design. Each phase has resulted in geographic expansion of the areas in which electric utilities and other market participants do business with one another.

Q. PLEASE DISCUSS THE FIRST STAGE OF FERC'S POLICY INITIATIVES – OPEN TRANSMISSION ACCESS.

A. As I discussed earlier, open access transmission was instituted by the FERC in its Order No. 888, issued in 1996. Order No. 888 had a profound effect on the electric utility industry. Before Order No. 888, vertically integrated utilities used their transmission systems primarily to serve their "native load" customers in their service territories. With open access, transmission networks began to be used more frequently for economic transactions within, between and among the utilities' territories. New industry entrants such as EWGs and power marketers began to use the interconnected electric grid to pursue competitive opportunities. Ultimately, in some jurisdictions, retail customers were given the opportunity to choose their electric suppliers, and those customers began to use the transmission system to access generation supplies outside of the host utility's control area to lower the customers' energy costs. Thus, as intended, Order No. 888 caused utilities' transmission systems increasingly to be used by third parties to enhance electric competition.

Order No. 888 also recognized the beginning of development of a new form of institution – the independent system operator ("ISO") - an independent entity that would operate a group of utilities' transmission systems and offer open access transmission service over the combined systems at a single rate. The FERC noted that some utilities were forming ISOs, stated that it wished to encourage the formation of those entities and spelled out certain principles for a "properly constituted" ISO, including independent governance, open-access non-discriminatory service at a single rate, responsibility for short-term reliability of the grid, etc. ISOs were the precursor of RTOs – a broader term meant to include a variety of types of regional transmission entities.

Q. PLEASE DESCRIBE THE SECOND STAGE OF FERC'S POLICY INITIATIVES – DEVELOPMENT OF RTOs.

A. In 1999, the FERC issued a Notice of Proposed Rulemaking that culminated in Order No. 2000, issued in late 1999. In Order No. 2000, the FERC noted that because of the changes in the structure of the electric industry resulting from Order No. 888, the transmission grid was being used more intensively and in different ways that it had in the past. The FERC concluded that regional institutions were necessary to address operational and reliability issues facing the industry, and to eliminate what the FERC perceived as residual discrimination in transmission services. FERC took note of the development of ISOs, but found the results to be haphazard and inconsistent. Accordingly, in Order No. 2000, the FERC took steps to strongly encourage RTO development, stating that it was the FERC's objective for all transmission-owning entities in the nation to place their transmission facilities under the control of appropriate RTOs.

The FERC envisioned that RTOs would enhance electric reliability by bringing under single management reliability functions that had been handled by a multiplicity of individual Control Area utilities. Also, as with ISOs under Order No. 888, FERC demanded that RTOs offer transmission service into, within, through and out at a single non-pancaked rate. RTOs, to be approved under Order 2000 must have adequate "scope and configuration", which means, practically speaking, that they must include many utilities and cover a large geographical area. RTOs also were required to conduct centralized planning for all member entities and were required to coordinate with adjoining RTOs. Finally, the FERC required RTOs to institute markets for energy imbalance and to adopt market-based congestion management systems.

Encouraged by Order No. 2000, Large RTOs have been formed or are planned over large parts of the nation. Significantly, as shown on AEP Exhibit No. 9, RTOs encompass all of the non-ERCOT area covered by the AEP System and the contract path used integration. ERCOT also acts as the equivalent of an RTO.

Q. ARE RTOS INVOLVED ONLY IN ELECTRIC TRANSMISSION FUNCTIONS?

A. No. Presently, RTOs are expected by FERC not only to direct the operation of member utilities' transmission systems and to offer open access transmission on those systems, but also to operate electric energy markets (generally capacity and day-ahead and hourly spot markets). The model for such RTO-run markets arose from the tight power pools in the eastern part of the country, particularly PJM. PJM had a long history of centrally dispatching the power supply resources of its member utilities. In compliance with FERC Order Nos. 888 and 2000, PJM adopted an independent governance structure, and became a FERC-approved RTO. As part of its centralized operations, PJM developed procedures under which all of its members' generating units are centrally dispatched on a least-cost basis using a bid-based system. That is, in any hour, PJM operates the generators who bid the lowest cost to serve its members' combined requirements.

Q. PLEASE DESCRIBE THE THIRD PHASE OF FERC'S POLICY INITATIVES – STANDARD MARKET DESIGN.

A. In 2003, FERC issued a Notice of Proposed Rulemaking on Standard Market Design ("SMD NOPR"), in which FERC proposed a standard electricity market platform for the nation, in which RTOs would operate electricity markets using centralized bid-based dispatch. The type of market envisioned by the SMD NOPR was patterned on PJM. The SMD NOPR proposed to make RTO membership mandatory. It also proposed to eliminate rate pancaking by eliminating transaction-based transmission charges in favor of access charges paid by customers. Thus, a seller of power from Utility A across utilities B and C to Utility D (or RTO A to RTO B) would not have to pay anything to the intervening utilities in the contract path. In fact, no transmission charge at all would be imposed on power sales transactions. Instead, all utility customers, (through their load-serving entities), would pay an access charge to compensate transmission owners for their costs of ownership. Note that this new rate design would eliminate additive rates not only within RTOs, but between adjoining RTOs, enabling energy to be transmitted for vast distances without any charge tied to the transaction. The SMD NOPR also proposed coordination among RTOs through joint operating agreements. The objective was to create "seamless" electricity markets over vast distances.

The SMD NOPR has not resulted in a final rule, but as I will show, several of the policies announced in that NOPR have been adopted in large portions of the country. Significantly, they have been adopted, or are in the process of being adopted, in the combined AEP system's service territory.

Q. CAN YOU DESCRIBE HOW FERC HAS IMPLEMENTED THE ABOVE-DESCIBED POLICY INITIATIVES WITH RESPECT TO THE AEP/CSW MERGER?

A. Yes. AEP's east zone is now incorporated into the PJM RTO, which is fully operational and incorporates the principles of FERC's SMD NOPR. AEP's west zone belongs to the Southwest Power Pool ("SPP") RTO, which recently has been approved by FERC as an RTO that meets the standards of FERC's Order 2000. The SPP RTO currently functions as the transmission system operator for its component utility systems and is in the process of developing and implementing additional functions that will implement the principles of FERC's SMD NOPR.

Q. ARE THE SPP AND PJM RTOS CONTIGUOUS TO ONE ANOTHER?

A. A third RTO, the Midwest Independent System Operator ("MISO") lies between the SPP and PJM RTOs. However, FERC has moved, beginning with a July, 2002 order, to eliminate any "seams" between the PJM and MISO RTOs, with the objective that transactions can be consummated across the PJM and MISO footprints just as if the two constitute a single RTO.

Q. WHAT IS THE STATUS OF THIS INITIATIVE?

A. Rate pancaking in the combined PJM/MISO has been eliminated, effective December 1, 2004. A MISO/PJM joint operating agreement ("JOA") has been negotiated and accepted by FERC and is now in operation. The JOA is a state-of-the-art agreement providing for a higher level of operational coordination and cooperation than had ever existed between or among existing RTOs, utilities or control areas. The MISO/PJM joint and common market is under development. The first phase of that development, implementation of an energy market within MISO, is currently projected to begin March 2005.

Together, these factors mean that an enormous electricity market is being created, and its development is well-advanced, in the combined MISO/PJM.

Q. HOW LARGE IS THIS COMBINED MISO/PJM ELECTRICITY MARKET?

A. It is huge. The area involved is shown on AEP Exhibit No. 9. It covers 18 states, and stretches from Manitoba Canada in the north and west to Virginia in the south and east.

Q. HAS FERC TAKEN SIMILAR ACTIONS IN SPP?

A. Yes. In its February, 2004, Order approving SPP as an RTO, FERC imposed a number of conditions including the following:

(1) SPP and MISO are to develop a market thereby adding to the PJM/MISO market discussed above.

(2) SPP and MISO are to negotiate a Joint Operating Agreement.

Q. WHAT IS THE STATUS OF THE TWO CONDITIONS YOU MENTIONED IN YOUR LAST ANSWER?

A. The joint and common market is in the process of development . In July, 2004 SPP filed with the FERC a JOA addressing early-stage operational coordination between SPP and MISO. This early "non-market to non-market" stage addresses the current situation in which neither RTO operates an organized energy market. In an Order issued October 1, 2004, FERC conditionally accepted the JOA. However, since implementation of MISO's energy market is scheduled for March, 2005, FERC directed SPP to file by December 1, 2004, a JOA containing mutually agreed provisions for "non-market to market" operations. The filing was made as scheduled.

Q. ARE THERE OTHER DEVELOPMENTS UNDERWAY THAT CONFIRM THE GEOGRAPHIC EXPANSION OF ELECTRIC UTILITY INTERACTION?

A. Yes. The three reliability councils in the area covered by PJM and MISO (The Mid-American Interconnected Network or "MAIN", The East Central Area Reliability Council or "ECAR" and the Mid-Atlantic Power Pool -- or "MAPP") are in the process of combining.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE ABOVE DISCUSSION?

A. I draw the following conclusions:

(1) federal policy has continually expanded operational and market coordination in the area encompassed by the combined AEP system;

(2) FERC has taken concrete steps to form a joint and common electricity market in the area encompassed by the combined AEP System and beyond;

(3) These events, which were underway at the time of SEC's approval of the AEP/CSW merger, make it even clearer that the combined AEP system is part of a single area or region.

Q. APART FROM FERC'S EFFORTS TO CREATE AN ORGANIZED MARKET COVERING SPP, MISO AND PJM, DO YOU CONSIDER AEP'S EAST AND WEST ZONES TO BE IN THE SAME WHOLESALE ELECTRICITY MARKET?

A. Yes. Our dispatchers and traders make decisions every day, and sometimes every hour, as to how much energy to transmit from one part of the system to another. As I note elsewhere, the prevailing direction of these transfers is from east to west. However, even when that condition prevails, decisions must be made as to how fully to load up our firm 250 MW path and whether to purchase additional transmission service on a non-firm basis. The decision to transfer a MWH of energy from east to west is a decision not to purchase that same energy in the west. These decisions affect the demand and therefore the market price levels in the west. Similarly, we at times transmit energy from west to east, when we conclude that the energy can be generated or purchased in the west at a price that is more attractive than our incremental cost of production or purchase price in the east.

Q. DOES THIS APPLY AS WELL TO THE RELATIONSHIP BETWEEN THE WEST OPERATING COMPANIES THAT ARE WITHIN THE SPP AND ERCOT?

A. Yes. The decisions of how much energy to transfer between ERCOT and SPP are made with regard to the relationship of wholesale prices between ERCOT and the SPP.

Q. IS THE COMBINED AEP SYSTEM IN THE SAME WHOLESALE POWER MARKET?

A. Yes, this market is fundamentally defined as all of the generating resources and load commitments that are situated in a common transmission infrastructure. AEP trades in this market most actively in the PJM, Cinergy Hub and Entergy Hub (which I refer to as the "Hubs"). The Hubs are different locations in this market that bring buyers and sellers of wholesale power together. All of the utility participants in these Hubs are either directly or indirectly linked through a common transmission infrastructure. The AEP East zone is in PJM and is adjacent to the Cinergy Hub. The AEP West Zone is adjacent to the Entergy Hub.

Q. IS THERE PRICE UNIFORMITY ACROSS THE HUBS?

A. No. While pricing in each Hub is primarily driven by the forces of supply and demand, there is not unlimited transmission capacity across the Eastern Interconnection. There are transmission constraints within the infrastructure. These transmission constraints mean that the power will flow throughout the entire transmission infrastructure with some limitations. These constraints cause price differentials between and even within the Hubs. AEP continuously monitors the prices and transmission availability between the Hubs and enters into economic transactions as they arise in each.

Q. HOW DOES THE FACT THAT WHOLESALE PRICES IN THE RESPECTIVE ERCOT, ENTERGY, AND CINERGY HUB ARE OFTEN AT DIFFERENT LEVELS AFFECT YOUR CONCLUSION THAT THIS IS ONE BROAD WHOLESALE ELECTRICITY MARKET?

A. No. The situation in this broad market is really analogous to what has occurred in PJM over the years. The centrally administered PJM market consists of numerous "nodes." A market clearing price is established from each node for each time period. When these prices separate, its related to is transmission constraints. Given a transmission system of infinite capacity, one would expect these prices to converge.

Q. IS THERE AN ADDITIONAL CONCLUSION THAT CAN BE DRAWN WITH RESPECT TO THE EFFECT OF THE ABOVE-DESCRIBED ELECTRIC UTILITY INDUSTRY DEVELOPMENTS ON THE "REGION" REQUIREMENT?

A. Yes. It is my understanding that the Appeals Court noted an "apparent conflict" between the SEC's approval of the AEP/CSW merger and certain decisions in which the Commission said that transmission contract rights cannot be relied upon to integrate two "distant" utilities. The Court said that there was "no reasoned analysis indicating that these prior policies were being deliberately changed" and indicated that the Commission did not consider the length of the contract path in deciding whether the New AEP meets the region requirement.

Q. IN LIGHT OF THE COURT'S LANGUAGE, WOULD YOU COMMENT ON THE SIGNIFICANCE OF THE DISTANCE OF THE CONTRACT PATH USED TO INTEGRATE THE AEP SYSTEM?

A. Yes. It should be evident from my foregoing testimony, and from the testimony of Paul Johnson, that the distance of a contract path used to integrate a utility should have far less relevance, if any, to either the interconnection requirement or the region requirement than it may have had in the past. This is true for a number of reasons:

First, contractual rights to use a utility's transmission system pursuant to FERC Order No. 888 do not vary according to the distance involved. Considering the pre-RTO situation in which contract paths were arranged across individual utility systems, a transmission path across a large system carries no fewer legal rights than a transmission path across a small system. For example, two parts of a utility holding company system could integrate using a contract path across Indianapolis Power & Light Company, a small utility serving the area of Indianapolis, Indiana, or across the pre-merger- AEP, an integrated system with an integrated transmission systems stretching hundreds of miles.

Second, RTOs have greatly expanded the distance of transmission contract paths. Now, each RTO is treated as a single entity for purposes of arranging transmission contract paths. So a transmission user can move across all of the utilities included in the MISO, for example, as part of a single leg of a contract path, and at a single rate. By reducing the number of entities from whom a transmission user has to obtain service, RTOs facilitate much longer power transactions than may have been readily available in the past, particularly in pre-Order No. 888 days, when each utility in a chain linking two "distant" utilities, would have to agree to provide service.

Third, FERC's actions in eliminating pancaked transmission rates between RTOs and removing other barriers, as I have discussed earlier, further extends the possibilities for long-distance power transactions. The FERC's order eliminating out and through rates between MISO and PJM, coupled with the JOA now enables customers on the east coast to access power resources as far away as Montana without paying any transaction-based transmission fee. In instituting these actions, FERC has specifically sought to remove distance as an impediment to economic power transactions.

Finally, the increased physical interconnection of utilities and the tremendous increase in the power carrying capability of transmission facilities described by witness Paul Johnson, have played a major part in the expansion discussed above. All of these factors justify the Commission in adopting a policy that regards distance as much less a relevant factor than may be reflected in the nearly sixty-year old decisions referred to by the Court.

Q. CAN YOU GIVE AN EXAMPLE OF A VERY LONG-DISTANCE POWER TRANSFER?

A. Yes. Attached as AEP Exhibit No. 10 is a copy of a presentation by SPP containing actual OASIS "tag" data showing a power transaction from Texas to New York.

VI. <u>INTERCONNECTED UTILITY TEST</u>

Q. THUS FAR YOUR TESTIMONY HAS FOCUSED ON FERC POLICY EXPANDING ELECTRIC UTILITY INTERCONNECTION AND ELECTRICITY MARKETS. IS THERE ANOTHER MARKET-ORIENTED REASON THAT SUPPORTS THE COMMISSION'S FINDING THAT THE COMBINED AEP SYSTEM IS PART OF A SINGLE AREA OR REGION?

A. Yes. It is my understanding that the Commission, for some purposes, has regarded the utilities that are directly interconnected with a subject utility as constituting the electric market area for that utility.

Q. DO YOU BELIEVE THIS APPROACH IS LOGICAL?

A. Yes. Historically, utilities have traded most frequently with their directly interconnected neighbors. Of course, for the reasons I discussed in the last section, this is changing, as electricity markets are expanding. For this reason, I think the direct interconnection model is still a valid model, although it is somewhat conservative. In light of recent developments, an electric market area or region can be said to encompass at least the two merging utilities and their directly interconnected neighbors, but the market could be much larger.

Q. FROM THE STANDPOINT OF DIRECTLY INTERCONNECTED UTILITES, IS THE COMBINED AEP SYSTEM CONFINED TO A SINGLE AREA OR REGION?

A. Absolutely. The electric systems that are directly interconnected with the combined AEP's operating companies are also highly interconnected with one another, such that the area formed by these interconnected entities forms one cohesive whole. This is graphically illustrated on AEP Exhibit No. 11, which shows on page 1, in green, the service territories of the combined AEP operating companies and the utility systems directly interconnected with them and on page 2, AEP's service territories and major transmission facilities of directly interconnected systems. Given the high degree of interconnection and interaction among electric utilities, it simply makes no sense to look at a subject utility in isolation when determining the area or region it is in.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

AEP Exhibit No. 5

ADMINISTRATIVE PROCEEDING
FILE NO. 3-11616

UNITED STATES OF AMERICA
Before the
SECURITIES AND EXCHANGE COMMISSION

In the Matter of **AMERICAN ELECTRIC POWER COMPANY, INC.**	:	**AFFIDAVIT OF WITNESS, J. CRAIG BAKER**

AFFIDAVIT OF WITNESS

I, the undersigned, being duly sworn, depose and say that the Prepared Testimony of J. Craig Baker served on behalf of the AEP Service Corporation in this proceeding is the testimony of the undersigned, and that the exhibits sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

____
J. Craig Baker

SUBSCRIBED AND SWORN to before me, a Notary Public, in Franklin County, Ohio on the ____ day of December, 2004.

____
Notary Public