BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Authority to Transfer Functional Control of Certain Transmission Assets to the Southwest Power Pool, Inc.	))))	Case No. EO-2006-0142

MEMORANDUM IN SUPPORT OF STIPULATION AND AGREEMENT

COMES NOW the Staff ("Staff") of the Missouri Public Service Commission ("Missouri Commission") and offers its Memorandum In Support of the Stipulation And Agreement filed in this proceeding on February 24, 2006.

Background

1. On September 28, 2005, Kansas City Power & Light ("KCPL") filed an Application seeking the Missouri Commission's approval of its participation in the Southwest Power Pool, Inc. ("SPP") in its function as a Regional Transmission Organization ("RTO"). The Application was accompanied by supporting direct testimony.

2. On September 30, 2005, SPP filed an application to intervene, along with direct testimony in support of KCPL's Application. Applications to intervene were subsequently filed by Aquila, Inc. ("Aquila"), the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") and The Empire District Electric Company ("EDE"). The Missouri Commission subsequently granted all four applications to intervene.

3. On January 12, 2006, the Missouri Commission adopted a procedural schedule. On February 10, 2006, the parties sought, and were subsequently granted, a suspension of the schedule in order to allow them to focus on concluding a settlement agreement. On February 24, 2006, following several months of diligent and intensive negotiations, five of the seven parties---KCPL the Staff, the Office of the Public Counsel ("Public Counsel"), EDE and SPP---filed their

Stipulation And Agreement ("Stipulation"), including a Transmission Service Agreement ("Service Agreement") between KCPL and SPP. The remaining parties, Aquila and the Midwest ISO, whose role was limited to monitoring the proceedings, subsequently filed pleadings confirming their non-opposition to the Stipulation and waiving their right to a hearing.

4. Also on February 24, 2006, the aforementioned signatory parties filed a Stipulation And Agreement reflecting the settlement of Case No. EO-2006-0141, which was established to address EDE's September 28, 2005 Application for authority likewise to join the SPP RTO. The discussion that follows addresses both Stipulation And Agreements ("Stipulations") and is identical to that which is presented in the Staff's concurrent filing of its Memorandum In Support Of Stipulation And Agreement in Case No. EO-2006-0141.

I. Introduction

The standard for the Missouri Commission to approve KCPL's and EDE's Applications to transfer functional control of certain of their transmission facilities to the SPP RTO is that such a transfer of these assets is not detrimental to the public interest. The criteria the Missouri Commission should use to determine whether or not the "not detrimental to the public interest" standard is met include both those that can be measured in dollars in terms of expected costs and benefits, and those that cannot be measured in dollars, such as the reliability of the interconnected power system, public safety, improvements or detriments to system planning, and impact on the jurisdiction of the Missouri Commission. Each of these criteria is addressed in detail in this Memorandum.

The Stipulations submitted by the Signatories thereto (EDE, KCPL, SPP, Public Counsel and the Staff) state on page 2 thereof that, subject to the provisions of the Stipulations, there is agreement that EDE's and KCPL's decision to participate in the SPP RTO is "prudent and reasonable," and that such participation is "not detrimental to the public interest."

II. Costs and Benefits of Participation in the SPP RTO

A. Pre-Market Start Cost-Benefit Studies

Generally the costs and benefits resulting from the proposed transfer relate to: 1) the costs paid to SPP for its administration of the RTO, and 2) the savings related to more efficient use of existing generation and transmission assets. In order to quantify these costs and benefits, the SPP Regional State Committee ("RSC")[1] contracted with Charles River Associates, International ("CRA") to perform a study that specifically focused on the SPP region. That study was to produce costs and benefits for: 1) the entire SPP region as it currently exists; 2) the individual utilities within the SPP region; and 3) the seven states in which these utilities serve retail customers (Arkansas, Louisiana, Kansas, Missouri, New Mexico, Oklahoma and Texas).[2] The clear result of this cost-benefit study is that SPP as an RTO is cost beneficial for the SPP region.

The CRA cost-benefit study addressed the following three basic scenarios:

(1) SPP acting strictly as a Regional Reliability Entity (RRE) with each utility providing transmission service on a stand-alone basis;

(2) SPP adding the function of being a regional transmission provider (RTP) that a) offers regional transmission service with Tariff Administration providing

[1] The SPP RSC has board members from five of the SPP states: Arkansas, Kansas, Missouri, Oklahoma and Texas. These board members are State Public Utility Commissioners from their respective states. The Missouri Commission board member did not participate in a substantive manner in any aspect of the study.

[2] Ralph L. Luciani and Ellen Wolfe from CRA have jointly filed direct testimony on behalf of CRA in both EO-2006-0141 and EO-2006-0142.

one-stop shopping at an SPP operated OASIS, and b) manages parallel path flows;[3] and

(3) SPP becoming an RTO with the Federal Energy Regulatory Commission ("FERC") requirement that it offer a) an Energy Imbalance Service ("EIS") market, b) an Independent Market Monitor ("IMM"), c) Regional Transmission Planning, d) Congestion Management; e) Ancillary Services, and f) Interregional Coordination.[4]

Table 1 gives the results in net benefits (benefits-costs) for the SPP region as measured in the CRA cost-benefit study.

Table 1
Net Benefits for the SPP Region
Ten-Year Net Present Value ($ million)

From (1) to (2) RRE to RTP	From (2) to (3) RTP to RTO	From (1) to (3) RRE to RTO
$70.5	$373.1	$443.6

In addition to SPP regional net benefits, the CRA study allocated these benefits to the various utilities and then to the various states. The results of these allocations are shown in Table 2 as allocated to Missouri for both KCPL and EDE.

Table 2
Net Benefits for Missouri
Ten-Year Net Present Value ($million)

	From (1) to (2) RRE to RTP	From (2) to (3) RTP to RTO	From (1) to (3) RRE to RTO
KCPL-MO	$4.8	$2.1	$6.9

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[3] As an RTP, the SPP meets three of the minimum functions that the FERC requires for an RTO: 1) Tariff Administration; 2) Parallel Path Flow Management; and 3) OASIS – determination of Available Transfer Capability (ATC).

[4] In addition to providing the remaining minimum functions required by the FERC, the RTO must also exhibit the following four characteristics: 1) independence from market participants; 2) appropriate configuration and scope; 3) operational authority; and 4) exclusive authority to maintain short-term reliability.

EDE-MO	$8.9	$39.6	$48.5
Missouri	$13.7	$41.7	$55.4

The results of the CRA allocations to the utilities indicate that EDE receives higher net benefits from joining SPP RTO than KCPL. The net benefits to KCPL are likely to be within the margin of error for studies of this type.[5] Most of the difference for KCPL compared to EDE is related to two factors: 1) KCPL is represented in the CRA study as losing significant revenues from the sale of transmission service assuming those sales are based on physical flows of power across the KCPL transmission system; and 2) KCPL is a net seller of power while EDE is a net buyer of power. However, if KCPL were not to join the SPP RTO:

1) As a stand-alone seller of transmission, KCPL may find that transmission customers will opt not to use KCPL's transmission services, at least not to the extent assumed in the CRA study, where the transactions that simply flowed over KCPL's transmission system were charged for transmission service; and
2) It is possible that KCPL will find it increasingly difficult to sell power in wholesale markets at market-based rates.[6]

While these are not certainties, and are extremely difficult to model as uncertain but probable events, it is clear the CRA study did not factor in these possibilities into its analysis for allocating costs and benefits.[7]

The results of the CRA study provide a strong indication that net benefits to Missouri ratepayers from KCPL and EDE joining the SPP RTO are positive. Cost-benefit studies are meant to be indicators of whether or not the dollar benefits of a particular decision are likely to

[5] The methods used for allocating benefits to the SPP utilities were a rough approximation of what might actually occur. Precise allocation of benefits to the utilities is not possible as it depends heavily on assumptions about short-term contractual arrangements for energy, which can change significantly with the EIS market.

[6] See Richard A. Spring's direct testimony at pages 12-13. Also see CRA (Luciani and Wolfe) direct testimony at pages 19-20.

[7] It would be nearly impossible and/or extremely expensive for CRA to have factored in all the combinations of Transmission Owners in or out of the SPP.

exceed the costs, and as such, should be interpreted as estimates, not as precise measurements. Many assumptions about future events and energy prices must be made in order to perform such studies, and to the extent that any of these assumptions are not fulfilled, the results of the study could be inaccurate. A major contributor to any lack of accuracy is the relative cost of fuels. Because the EIS market allows greater substitution of lower cost generation (typically coal) for higher cost generation (typically natural gas), the expected result for higher natural gas costs is that the EIS market with SPP as an RTO will provide even larger benefits, but on the other hand, higher coal prices could result in lower benefits.[8]

B. Post Market Operations Cost-Benefit Studies

1. Interim Report

While, the CRA studies are the best information available at the time that they were performed, the Staff supports the Missouri Commission granting only interim approval of EDE's and KCPL's participation in the SPP's energy EIS market, and set out as a provision of the Stipulations the requirement that EDE and KCPL each submit an "Interim Report" that measures net benefits from the SPP EIS market.[9] The Staff believes that this form of accountability is a key component to prudent management for both utilities. The separate Interim Report contemplates that the actual (modeled) production costs for EDE and KCPL to participate in the EIS market will be compared to an estimate of what their production costs would have been absent such participation. While the parties agreed to one such filing by EDE and by KCPL as the basis for each utility's continued participation in the EIS market, it is the Staff's expectation that both EDE and KCPL will monitor their respective production costs from the EIS market on

[8] Subsequent to CRA performing its cost-benefit analysis, natural gas prices have increased beyond what was anticipated. The CRA study was updated for the higher natural gas prices and, as expected, showed increased net benefits for both EDE and KCPL.

[9] See provision (b) in Section II.A(2) of the Stipulations, which is detailed in Section II.D of the Stipulations.

an ongoing basis as well as make the types of comparisons that are required in the Interim Report.

2. Changes To Cost-Benefit Assumptions – Triggers EDE and KCPL Filings

Provisions for EDE and KCPL filing an update regarding their continued participation in the SPP prior to the end of the seven-year interim period were included in Section II.A(2)(d) "SPP Administrative Cost Provision," and Section II.A(2)(e) "SPP Geographic Scope and Function Provisions" of the respective Stipulations. The reason for these provisions is that the CRA cost-benefit analysis is based on assumptions regarding SPP's costs to administer the RTO as well as on the number and size of the participants in the EIS market. If either the administrative SPP costs go up significantly (greater than a 25% increase) or participation in the market goes down significantly (greater than a 25% decrease), EDE and KCPL will each file a pleading with the Missouri Commission to address the merits of their continued participation in the SPP.

3. Additional Cost-Benefit Analysis

In addition to facilitating an EIS market, the SPP is evaluating the possibility of having markets for Ancillary Services involving generation – specifically, regulation and operating (spinning and quick start) reserves. In addition, the SPP is evaluating consolidation of control areas, a day-ahead energy market and switching to financial transmission rights. None of these services is included in the current functions of the SPP, and the SPP intends to have a cost-benefit analysis performed prior to making any recommendations for going forward with these services. In Section II.D(2) of the Stipulations, there is an agreement by SPP to include Staff's and Public Counsel's participation in the development of any and all such cost-benefit analyses.

C. Charges Related to SPP Transmission Upgrades

The Stipulations recognize that EDE and KCPL may receive SPP charges for Base-Plan transmission upgrades that are needed for regional reliability, but that are not built in their transmission zones.[10] The Staff views these as transmission charges associated with delivery (purchases and sales) of power from wholesale markets, either through bilateral contracts or through the EIS market.[11] In Section II.B(3)b of the Stipulations, EDE and KCPL respectively commit to actively participating in the SPP planning process to help ensure cost effective means for meeting the reliability needs of the SPP region. In addition, SPP commits to structuring its transmission planning process so as to identify cost effective upgrades needed to meet the region's reliability needs.

In addition to Base-Plan transmission upgrades, EDE or KCPL may build supplemental upgrades to improve local transmission reliability, serve growth of native load, add to existing transmission service, decrease transmission congestion, or support a generation interconnection. In Section II.B(3)c of the Stipulations, if the cost to EDE or KCPL of any one supplemental upgrade project exceeds twenty-five million dollars, each agrees to provide the Staff and Public Counsel with a report detailing the need, costs and benefits anticipated in connection with such a supplemental upgrade.

III Jurisdictional Issues and the Role of the Missouri Commission

A. Impact on the Jurisdiction of the Missouri Commission

The direct testimony filed by KCPL, EDE and SPP did not address a critical issue; namely, recognition of the jurisdiction of the Missouri Commission over the rates paid by

[10] The cost allocation plan for Base Plan upgrades was approved by the FERC in Southwest Power Pool, Inc., Order on Proposed Tariff Provisions, Docket No. ER05-652-000, April 22, 2005.

[11] Other load serving entities will use EDE's and KCPL's transmission facilities for wholesale transactions, and through the cost allocation plan will be required to pay EDE and KCPL for the use of those facilities.

Missouri bundled retail ratepayers for transmission service from jurisdictional generation assets. The recognition of the jurisdiction of state commissions relating to ratemaking authority was set out in the FERC's White Paper.[12] The FERC stated that it will recognize states' ratemaking authority via a contract (service agreement) between the RTO and the utility that specifically allows the utility to take network service from the RTO but does not require the utility to directly pay the RTO for service to its Bundled Retail Load at the network service rate that is set in the RTO's tariff. This type of service agreement was negotiated between AmerenUE and the Midwest ISO, submitted as a part of a stipulated settlement in Case No. EO-2003-0271, approved by the Missouri Commission and subsequently approved by the FERC. In Section II.B of the Stipulations, Service Agreements between SPP and KCPL and between SPP and EDE, which are designed to accomplish this same result, are provided for as a condition for approval of the respective utilities' requests for authority to transfer functional control of certain transmission assets to the SPP RTO. Copies of those Service Agreements are included as Attachment A to the respective Stipulations. EDE and KCPL have agreed that a condition precedent to their respective participation in the SPP RTO is the acceptance of the Service Agreement by the FERC.

B. Rate Terms and Conditions

The Service Agreement is meant to ensure that the Missouri Commission continues to set the transmission component of EDE's and KCPL's rates to serve their Missouri Bundled Retail Load. In effect, the Service Agreements prevent the transfer of transmission rate setting for EDE and KCPL to FERC determined SPP rates. In particular, this is accomplished in Article III, Section 3.1 of each of the Service Agreements, which states that EDE and KCPL "shall not pay

[12] Wholesale Power Market Platform, April 28, 2003.

the rate set forth in Schedule 9 of the SPP [Open Access Transmission Service Tariff ("OATT")] for using its own facilities to serve their Missouri Bundled Retail Load." Schedule 9 is the SPP OATT schedule that sets the rate for network service for each of the various transmission zones. In addition to direct transmission service, to the extent that EDE and KCPL self-provide certain ancillary services related to regulation, operating (spinning and quick start) reserves, they will not be required to pay SPP for those services. (Article II, Section 3.2) This provision does not mean that EDE and KCPL will not pay for services that SPP does provide and from which they are expected to benefit. (Article II, Section 3.3). It should also be pointed out that both EDE and KCPL will be network service customers[13] of SPP and will be subject to all non-rate related terms and conditions under the SPP OATT applicable to Network Integration Transmission Service. (Article II, Section 3.4).

Section II.B(2) of the Stipulations contains a good example of the purpose of the Service Agreement. In brief, this example illustrates that while FERC incentives[14] may be included in SPP rates for Schedule 9 OATT, they would not apply to EDE's and KCPL's transmission investments used to serve Missouri Bundled Retail Load unless the Missouri Commission makes the decision to include such incentives.

C. Unanticipated FERC Actions – Disapproval of the Service Agreement

The Stipulations recognize the possibility that FERC may not approve the Service Agreements as presented in Attachment A thereto. If changes are required by the FERC, and SPP and EDE or KCPL can come to an agreement regarding such changes, then revised Service Agreements reflecting that agreement will be provided to the Missouri Commission, and the

[13] Network transmission service is transmission service from the utility's designated network resources (generation sources) to its entire load.

[14] The FERC has proposed various incentives, including higher rates of return, for investment in new transmission facilities.

Staff and Public Counsel. Thereafter, within 90 days, any signatory to the Stipulations can file with the Missouri Commission regarding the nature of such revisions and make recommendations as to whether or not the Missouri Commission should rescind its approval or maintain its approval, with or without additional conditions.

D. Seams Agreements

Having utilities in two separate RTOs creates a seam within Missouri. However, this seam is addressed by a Joint Operating Agreement ("JOA") between the SPP and the Midwest ISO. The primary purpose of the JOA is to ensure reliable operations of the interconnected transmission system. The JOA deals primarily with information provided between the two RTOs, and with various responses when conditions threaten reliable operations at the seam. In addition, the JOA must incorporate the rights of each RTO to, in effect, use the other RTO's transmission system through either power contracts or loop flows. The FERC has also required RTOs to address the issue of how to improve economics through what it calls a Joint and Common Market. In brief, Joint and Common Market provisions deal with how to best interface the two energy markets to take advantage of potential cost savings.

It is also important to note that there are non-RTO transmission providers in Missouri (*e.g.*, Associated Electric Cooperative, Inc.) that also form a seam where they are connected to transmission systems within the SPP and Midwest ISO. In Section II.A(2)(g) of the Stipulations, SPP agrees to "use its best efforts to maintain joint operating agreements with the transmission providers at SPP's Missouri seams."

E. Provisions for EDE and KCPL Withdrawal from the SPP RTO

Section II.E of the Stipulations addresses four considerations related to EDE and KCPL possibly withdrawing from the SPP RTO. First, the Signatories to the Stipulations agree (and the

Missouri Commission is being asked to approve) that if the Missouri Commission were to rescind its approval of EDE's and KCPL's participation in SPP, it would take at least twelve months for these utilities to fully effectuate such a withdrawal. Second, if such an order to rescind were to come later than twelve months before the expiration of the Interim Period, the Interim Period should be extended to allow for at least twelve months for EDE and/or KCPL to exit the SPP. Third, the Stipulations recognize that EDE and KCPL will be required to pay applicable exit fees and may have other obligations within the SPP that would continue beyond their exit. Fourth, if either EDE or KCPL would wish to withdraw from SPP and join another RTO, each has agreed to seek prior approval from the Missouri Commission for this action, as well as for other actions that involve a "fundamental change in its participation in SPP." This could include participation in SPP through an Independent Transmission Company ("ITC").

F. Evaluation of Midwest ISO as an Alternative to SPP

The testimony submitted in these cases by EDE and KCPL did not present a comparison of net benefits between joining the SPP versus the Midwest ISO. Moreover, calculations of net benefits from EDE and KCPL joining the Midwest ISO were not available. Both SPP and Midwest ISO offer similar, but not identical services, and, in the Staff's view, it would be difficult if not impossible to achieve a truly fair result by using regional dispatch models to differentiate between the energy markets of the two RTOs. In this regard, the interconnections that EDE and KCPL have with the other utilities in the SPP are critical to the Staff, as well as the history of experience that EDE and KCPL have with the SPP organization. Finally, the Staff believes that it is in the public interest to support the incremental approach that SPP is taking to providing additional services. Specifically, while the Midwest ISO market design included both a day-ahead market and financial transmission rights, the SPP will perform incremental cost-benefit analysis to determine whether or not these services provide sufficient benefits to be offered at a later date. As a part of this evaluation, the SPP will use its experience with: 1) the functioning of the EIS real-time market, absent a day-ahead market; and 2) schedules based on physical transmission rights, absent financial transmission rights.

IV. Other Factors to Consider

A. Reliability of the Interconnected Power System and Public Safety

In moving from stand-alone utilities, with each providing open access transmission service, to regional transmission service provided by SPP, improvement in reliability comes from the simple fact that transmission service will be provided on an integrated regional basis in which all of the physical flows are more accurately taken into account. While individual utilities can take into account known loop flows from transmission service that is being provided by neighboring utilities, the communications process that would be required to keep each individual transmission provider up to date on actual transmission use would be a daunting task, and could easily result in out-of-date and inaccurate information. This circumstance makes it difficult to achieve the goal of maintaining minute-to-minute reliability of the transmission system. The ability to curtail transactions through Transmission-Line Loading Relief (TLR) is therefore an absolute necessity. However, when this information is processed by a single entity (the RTP), the chances for dated and inaccurate information significantly decrease, and the overall reliability of the transmission network increases.

In moving from an RTP to an RTO with an EIS market, the information flows change from physical schedules of power submitted by utilities to information on resource plans of individual load-serving entities along with bids for generation.[15] In this case, the RTO is sending out dispatch signals every five minutes rather than attempting to adjust congestion problems on an hourly basis through the use of TLRs. With the additional flexibility provided to the RTO to dispatch generation, the RTO is better able to manage congestion and thereby improve the reliability of the transmission system. Because of this greater flexibility in dispatching generation, the use of TLRs is limited to emergency situations where there is not sufficient generation offered into the market to meet the load in a specific sub-region. For example, a generation plant is out of service and at the same time a transmission line trips out that is providing a path for alternative generation to reach load. While emergency situations would result in TLRs in a transmission system without centralized dispatch, without the ability to quickly and economically redispatch because of congestion, the RTP must use the TLR tool to not only deal with emergency situations but also to manage day-to-day congestion.

The utilities owning the transmission facilities will still be responsible for maintaining their transmission systems and responding to emergencies within their individual systems. Moving from being a stand-alone Transmission Provider to belonging to a RTP or RTO will not lessen the Transmission Owners' responsibilities to ensure that their bulk power systems do not threaten public safety. If anything, removing the responsibilities to also manage the provision of transmission service should allow the Transmission Owners to put greater focus on issues related to public safety.

[15] There may still be physical schedules submitted in the SPP's EIS market as individual load-serving entities are allowed to self-dispatch generation. However, schedules for generation that is not self-dispatched, but is instead offered into the EIS market represent financial, rather than physical schedules. Moreover, the purpose of the schedule combined with an offer is that by scheduling, the load-serving entity does not have to pay any congestion costs from that generation source to its load.

B. Regional Transmission Planning

In the case of the SPP RTO, Transmission Owners retain a responsibility to plan for the expansion of the transmission grid to meet the needs of the generation and load located within their individual transmission systems. As an RTP, the SPP did not have a FERC directive to coordinate transmission planning on a regional basis, but as an RTO, the FERC requires the RTO to determine the transmission needs for the region to meet reliability needs. This can work in one of two ways. First, the SPP can simply coordinate the transmission plans of the individual Transmission Owners to ensure that reliability needs are being met. Second, the SPP can go beyond simple coordination to a detailed review of transmission plans to determine from a regional basis the overall best transmission expansion plan for meeting the region's reliability needs.

With the approval of the cost allocation proposal put forth by the SPP RSC and the subsequent approval by the FERC, any upgrades approved by the SPP Board as Base-Plan Projects are eligible for regional cost sharing.[16] However, in order to be approved as a Base Plan Project, the SPP must determine that the project meets reliability needs within the region and that it is part of a set of best alternatives for meeting those needs. Projects that do not meet these criteria can still be constructed, but are not eligible for regional cost sharing. For example, a load-serving entity may want to increase the import capability to its load as a way of reducing purchased power costs. Such a project may have net benefits to the load and can be requested and paid for by the load-serving entity, but if not needed to fix reliability issues, would not qualify for regional cost sharing. If such a project did help to fix a reliability issue and replaced a SPP planned project for reliability, then the project would qualify for regional cost sharing up

[16] Under Regional Cost Sharing, 1/3 of qualified costs are included in a region-wide postage stamp rate, and 2/3 of qualified costs are allocated to pricing zones (utility control areas) that benefit from the upgrade in proportion to the decrease in megawatt-mile use of the transmission systems in each benefiting zone.

to the cost of the project being replaced. Any additional cost would be paid for by the load-serving entity requesting the upgrade.

One of the major benefits of regional planning is that reliable transmission service can be provided on a region-wide basis at a lower cost. Without regional coordination, an individual transmission owner is not likely to recognize the impact that loop flows from generation within its transmission system will have on neighboring systems. Even if this coordination is provided among individual systems on a voluntary basis (this is one of the functions of the Regional Reliability Council), there may not be any attempt to reduce costs on a coordinated basis, as is the case for SPP's regional planning as a FERC approved RTO.

Regional planning by an independent entity (*e.g.*, SPP) is better able to provide transmission on a non-discriminatory basis to vertically integrated utilities, transmission dependent utilities and independent power producers. Conversely, when the plans of a transmission owning utility are not subject to an independent review, there is no assurance that the utility will provide transmission upgrades on the same basis to loads served by transmission dependent utilities or to generation provided by independent power producers, as it does to its own load and generation.

C. Price Transparency and Independent Market Monitoring

The primary advantage of having an EIS market is that the spot-market price for electricity is posted and available for public review. Not only does this provide a basis for market participants to better understand the operations of the spot energy market, but it also provides a sound basis for the IMM to determine whether or not any market participant is attempting to manipulate the market. The SPP Board of Directors has entered into a contract with Boston Pacific Company to act as the IMM for the SPP.

While the FERC does not assure utilities that are in an RTO that they will necessarily receive authority for market-based pricing of wholesale energy sales, having a transparent spot market and an IMM does provide a strong case for FERC allowing utilities to engage in market-based pricing. Specifically, the IMM is required to report to FERC if there are congestion issues within the RTO that would allow a market participant to exercise market power. If such a situation exists, then some form of market power mitigation is required; *e.g.*, certain units might be required to offer energy into the spot market at cost. Finally, price transparency provides information to market participants concerning congestion costs. This information is extremely valuable in identifying areas of the transmission system where upgrades are likely to provide the most cost effective congestion relief.

D. Stand-Alone, Non-Independent Transmission Providers

It is important for the Missouri Commission to also take into account what might happen if it were to deny EDE's and KCPL's Applications to join the SPP RTO, or at some future date, to require EDE and/or KCPL to withdraw for the SPP RTO. Moreover, if that were to occur, EDE and/or KCPL would face several alternatives: 1) operate as a stand-alone, non-independent transmission provider; or 2) possibly stay with the SPP as its RTP; or 3) join the Midwest ISO or another RTO as its independent transmission provider.

On September 15, 2005, the FERC issued a Notice of Inquiry (NOI) concerning reform of its Order No. 888 regarding requirements for non-independent transmission providers to offer open access to their transmission systems on a non-discriminatory basis.[17] Dr. Michael Proctor of the Staff has performed a detailed review of this NOI and has concluded that the FERC will make it more difficult for non-independent transmission providers to be able to unduly

[17] FERC Docket No. RM05-25-000.

discriminate against competitors with respect to offering transmission services. In short, it will become increasingly difficult for a vertically integrated utility to become or remain a non-independent transmission provider. The CRA study attempted to estimate the cost of the EDE and KCPL to function as a non-independent transmission providers, but CRA did not factor into its estimates the additional costs that might flow from FERC reform of Order No. 888.

In this regard, neither EDE nor KCPL has functioned as a non-independent transmission provider since SPP began to offer regional transmission service in 1998, and both EDE and KCPL have participated by taking wholesale transmission service under the SPP tariff. In addition, EDE began taking network service for its retail load under the SPP tariff in 2002. Thus, neither EDE nor KCPL has provided transmission service to wholesale customers, involving the operation of an OASIS and the determination of ATC. Taking on these additional functions would add substantial costs to the transmission operations of both utilities.

Finally, both EDE and KCPL are active in wholesale power markets; KCPL primarily as a seller of generation, and EDE primarily as a purchaser of generation. This active involvement as a market participant would result in conflicts of interest between the generation and transmission functions for both companies. Recently FERC found that EDE and KCPL[18] did not pass the safe harbor tests for <u>not</u> having market power in their respective service territories.

V. Conclusion

The Staff believes that the parties have crafted a Stipulation that accommodates KCPL's request for authority to transfer functional control of certain of its transmission facilities to the SPP RTO, while protecting the public interest.

[18] KCPL was granted market-based rate authority by the FERC after it filed additional information regarding the prices at which it has sold electricity.

WHEREFORE, the Staff submits its Memorandum in Support and respectfully recommends that the Missouri Commission issue its Order approving the Stipulation And Agreement, filed in this proceeding on February 24, 2006.

Respectfully submitted,

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Certificate of Service

I hereby certify that copies of the foregoing have been mailed, hand-delivered, transmitted by facsimile, or electronically mailed to all counsel of record this 14th day of March 2006.

/s/ Dennis L. Frey