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June 09, 2004

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Dale Hardy Roberts
Secretary/Chief Regulatory Law Judge
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P.O. Box 360
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FILED
JUN 0 9 2004
Missouri Public Service Commission

RE: In re: Application of Union Electric Company
Case No. EO-2004-0108

Dear Mr. Roberts:

Enclosed for filing please find an original and eight copies of the Reply Brief of Union Electric Company d/b/a AmerenUE and an original and eight copies of AmerenUE's Suggested Findings of Fact, Conclusions of Law and Ordered Paragraphs. These documents are being filed to meet today's deadline. As stated in the Certificates of Service, copies of these documents are being served on counsel of record.

Thank you for your assistance.

Sincerely,

James B. Lowery

Enclosures
c w/enc: Counsel of Record

FILED

JUN 0 9 2004

Missouri Public Service Commission

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

Case No. EO-2004-0108

REPLY BRIEF OF UNION ELECTRIC COMPANY D/B/A AMERENUE

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I. OVERALL RESPONSE TO BRIEFS[1]

A. This Commission is perfectly capable of discharging its duty at the appropriate time to ensure that utilities provide adequate and reliable service at just and reasonable rates.

Staff's approximately 130 page brief, and the Office of the Public Counsel's ("OPC") brief, both make at least one thing clear: they apparently believe this Commission is powerless to discharge its duty at the appropriate time to ensure that utilities provide adequate and reliable service at just and reasonable rates. Their belief is reflected in their insistence that this Commission deny this transfer based upon speculation about future ratemaking consequences for which probabilities cannot be established, or for which the probability is low, and which in any event have not and cannot be quantified with any reasonable degree of accuracy, even assuming they are relevant to the issues in this case. Staff and OPC's speculation that these future impacts would occur depends on all of the following assumptions occurring/materializing:

(i) the Company's future costs must be greater post-transfer;
(ii) if (i) occurs, those greater costs must not be offset by greater revenues;
(iii) any future net increase in costs must fall in a test year;
(iv) any future net increase in costs must not be reduced through normalization or other adjustment;
(v) other transfer-related benefits, such as the reliability gained by serving Missouri's native load with Company-owned base load generation versus relying on purchased power or gas-fired combustion turbine generators (CTGs), must not outweigh any net increase in costs;
(vi) the benefits of removing the Company and this Commission from having to at times juggle the competing demands of two different regulatory regimes must not outweigh such costs; and
(vii) the Commission must allow for recovery of any net increase in costs in rates in any event.

Though the Company has said – repeatedly (on-the-record and under oath)[2] – that it is not seeking ratemaking approval of the transfer, Staff and OPC continue to mischaracterize the

[1] This Reply Brief is in response to the initial briefs of both Staff and OPC.
[2] Tr. at p. 290, l. 1-16; p. 291, l. 4-10; p. 424, l. 24 to p. 425, l.5; p. 1696, l. 12-17.

approval the Company seeks because they know unless they can convince the Commission that this case ought to be turned into a speculative ratemaking case, the transfer must be approved.

Their Briefs are replete with this hyperbole. Their approach to this case has created *the* "poster child" for the concerns the Case Efficiency initiative currently underway at the Commission is designed to address.[3] It is a prime example of what seems to have become commonplace. A utility comes to the Commission for a particular permission arguably required by statute, in this case to transfer assets (located in another state no less) under Section 393.190.1, RSMo. and is met with opposition from Staff and OPC designed to extract ratemaking concessions from the utility which will better "set up" or "position" Staff and OPC to advance their ratemaking arguments in future rate cases.[4] That is, at bottom, what their opposition is about. And that is why they continue to misstate what the Company is requesting in this case.

The Company states again: The Company does not seek ratemaking approval of the transfer, of the asset transfer agreement, or of the transfer price.[5] It assumes, and in fact expects, that the Commission's order will so provide. Indeed, in direct contradiction to what Staff asserts in its brief, Staff witness Ron Bible articulates the "no ratemaking" impact in his testimony.[6] Staff and OPC assert that the affiliate transaction rules apply and that the terms of the transfer agreement and transfer price may not comply with those rules. In response, the Company has requested, if this Commission determines the rules apply, that the transfer agreement and price be approved *to the extent necessary to satisfy the affiliate transaction rules or to otherwise*

[3] The hearings in this case covered seven full days, generated 88 exhibits, over 1,900 pages of live transcript, and 22 separate pieces of pre-filed testimony. As Judge Thompson observed, "Just want you guys to know that I'm impressed. We're approaching the exhibit level seen only in rate cases." Tr. at p. 951, l. 15-16. As previously noted, Staff's initial brief is in excess of 130 pages.
[4] It is apparent that the arguments they make regarding the Joint Dispatch Agreement ("JDA"), Electric Energy, Inc. ("EE Inc."), and SO_2 allowances are all directed toward the Company's next rate case.
[5] Note 2, supra.
[6] Ex. 3 at p. 3, l. 16-24.

sustain a waiver of such rules.[7] The only "ratemaking" treatment the Company seeks is listed in numbered paragraphs in Mr. Kevin Redhage's surrebuttal testimony (Ex. 2), at pages 13-14, and deals with the nuclear decommissioning fund.

B. **This Commission must decide this case based upon the facts and the law, and not based upon speculation.**

Staff and OPC's briefs clearly (and improperly) invite this Commission to erroneously speculate about all kinds of unproven and unlikely "detriments."

The job (and the authority) the Legislature gave this Commission in this asset transfer case is to decide, based upon the substantial and competent evidence of record, whether the transfer is detrimental to the public interest.[8] State ex rel. AG Processing, Inc. v. Pub. Serv. Comm'n, 120 S.W.3d 732, 735 (Mo. banc 2003); State ex rel. City of St. Louis v. Pub. Serv. Comm'n, 73 S.W.2d 393, 400 (Mo. banc 1934); State ex rel. Fee Fee Trunk Sewer, Inc. v Litz, 596 S.W.2d 466, 468 (Mo. App. E.D. 1980) . In making that determination, this Commission must be mindful of several important, binding, and controlling principles underlying public utility regulation in this state, as follows. First, the Commission has a duty to "balance the interests of ratepayers with that of the shareholders" of the utility. State ex rel. Union Electric Co. v. Pub. Serv. Comm'n, 765 S.W.2d 618, 625 (Mo. App. W.D. 1989); State ex rel. Washington Univ. v. Pub. Serv. Comm'n, 272 S.W. 971, 973 (Mo. banc 1975). The Commission cannot take over the management of a utility. City of St. Louis, 73 S.W.2d at 400. The Commission must be mindful of the fact that the right of a utility to transfer its property is an important incident of its ownership of property and that such a right should not be denied "unless there is compelling evidence on the record showing a public detriment is likely to occur." In re Kansas City Power and Light Company, Case No. EM-2001-464 (Order Approving

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[7] Id.

[8] This is discussed in more detail in the Company's initial brief at pages 11-13.

Stipulation and Agreement and Closing Case, issued Aug. 2, 2001, 2001 Mo. PSC LEXIS 1657) (*citing* In re Missouri Gas Company, 3 Mo.P.S.C.3d 216, 221 (1994)). This Commission cannot speculate about future asset-transfer related rate increases (or, for that matter, decreases). AG Processing, 73 S.W.3d at 736. This Commission can and will deal with rate impacts, if and when they occur, once they are known, can be quantified, and can be considered together with *all* of the Company's *then-existing* costs and revenues and *then-existing* rate base. Nothing about this transfer removes or modifies any tool at the Commission's disposal necessary to properly ensure that just and reasonable rates exist, as the numerous pieces of evidence of record in this case, included as Appendix A to this Reply Brief, demonstrate.

C. Neither the Commission nor the Company is in the business of acting as an insurance company for ratepayers.

An overall theme – perhaps *the* overall theme – of Staff's and OPC's entire cases is their advocacy of "insurance" against all kinds of horrible things they allege *might* occur in the future. This very issue came up at the hearings during cross-examination from the bench of Dr. Michael Proctor.

> Q. So obviously anybody's ability to read the stars and see what is going to happen in the future is limited. So what happens if market conditions change, unfortunate monetary pressures of one sort or another occur. I mean, that's simply natural, is it not, to some degree? A. Yes ...[9]
>
> Q. Okay. So I'm following you. Because, I mean, let's say the transfer doesn't happen. There's always some percentage, is there not, that something terrible is going to happen that's going to cause bad things for the ratepayers? A. That's correct. Q. I mean, look at the Hawthorn plant blowing up. Who could have predicted that? So we are not in the business of insuring ratepayers against calamity. A. I agree.[10]

The fact that neither the Commission nor the Company are in the business of acting as insurance companies is simply reflective of the principles of public utility law discussed above –

[9] Tr. at p. 1791, l. 19-24.
[10] Tr. at p. 1793, l. 20 to p. 1794, l. 4.

fairness to the utility and the ratepayers, the importance of private property rights, and the need for compelling evidence of likely detriments, not speculation – before those private property rights can be denied. At bottom, the Company has met its burden to show that the transfer is not detrimental, plus, as discussed in our initial brief and herein below, has gone beyond its burden to show affirmative benefits. Staff and Public Counsel, though they raise a huge number of issues they claim may be detriments, have not presented substantial and competent evidence – certainly not compelling evidence – that a single one of the detriments they allege are likely to occur, or that they are present or direct detriments. The *only* way the Commission could possibly deny permission for the transfer would be to improperly speculate about the future effect on rates. Yet approval of this transfer will not decide what AmerenUE's future revenue requirement for ratemaking purposes will be, what AmerenUE's rate base will be, or what AmerenUE's future rates will or will not be. Approval of this transfer will simply determine whether AmerenUE can transfer these Illinois assets to AmerenCIPS.

Approval of this transfer accomplishes something else. It makes available to Missouri proven, Company-owned base load generation consistent with this Commission's clear preference expressed in its Order approving the settlement of the EC-2002-1 case – a preference that might best be summed up with the old adage "one in the hand is worth two in the bush." That base load generation is in place. It is proven. It is connected to existing, proven and available transmission. This transfer should be approved, and approved promptly.

D. Staff and OPC's position on the *AG Processing* case stretches its holding beyond all reasonable bounds and puts this Commission in the untenable position of speculating about future transfer-related rate impacts.

Staff devotes 20 pages to an historical and largely academic discussion of the bounds of the Commission's authority in asset transfer cases. Staff and OPC then try to disavow this Commission's prior decisions in asset transfer cases where it was (and in fact remains) clear that asset transfer cases are not ratemaking reviews, but rather, are principally concerned with ensuring that asset transfers do not negatively affect reliable and adequate utility service. In two prior filings,[11] the Company has discussed the AG Processing case which makes no fundamental change in the law in this regard. The Company will not further enlarge the record with a repeat of that entire discussion here, but a few points do bear addressing herein.

1. Staff and OPC grossly overstate the holding and impact of *AG Processing.*

Page 1 of Staff's brief contains two gross overstatements regarding AG Processing. First, Staff alleges that the Commission must evaluate seemingly every "future effect" [meaning every possible future ratemaking impact] of proposed asset transfers no matter how speculative or remote are those "effects." Second, Staff alleges that the legal standard for approving the transfer is *no longer* the "not detrimental to the public interest" standard.[12] OPC makes similar arguments at pages 5 and 8 of its brief, referencing what it calls the need to "ensure" against a "future detriment" relating to rates, and the "*risk*" of higher rates (emphasis in original).[13]

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[11] See Ex. 69, at pp. 11-14; the Company's initial brief at pp. 51-56.

[12] Staff's brief is vague on this point, but apparently Staff's bases this contention on certain "best interests" language in the affiliate transactions rules or on its false premise that this is in effect a case where ratemaking issues are decided. As discussed in Section VI of this Reply Brief below, Staff's arguments are dead wrong, and misread and misapply the rules.

[13] With regard to OPC's statements about the "risk" of higher rates, even OPC concedes only such risks that are "likely" to occur could constitute detriments sufficient to authorize denial of permission for the transfer. OPC's brief at p. 9.

There is not one statement in the AG Processing decision that instructs this Commission to evaluate future speculative ratemaking "effects." Rather, the Supreme Court cautions the Commission against doing just that:

> The fact that *the* acquisition premium recoupment issue could be addressed in a subsequent ratemaking case did not relieve the PSC of the duty of deciding *it* as a relevant and critical issue when ruling on the proposed merger. *While the PSC may be unable to speculate about future merger-related rate increases*, it can determine whether *the* acquisition premium was reasonable (emphasis added).

AG Processing, 120 S.W.3d at 736.

Staff and OPC ask this Commission to do exactly what the Supreme Court recognized the Commission *cannot do*: "speculate about future [asset] transfer-related rate increases." AG Processing stands for one thing, and one thing only: when this Commission is faced with a non-speculative known and quantified merger premium ($92 million), it must consider that merger premium in connection with its overall determination of whether or not the merger ($279 million) would be detrimental to the public interest.[14] No one denies that this Commission, in a case decided after the AG Processing decision was issued,[15] determined that AG Processing did not require this Commission to speculate about an *unknown and unquantified* merger premium (though one might have existed). As the quote included in Staff's brief at page 31 indicates, all the Supreme Court said in AG Processing was that the Commission, when it has a known and quantified merger premium before it, "can [and should] determine whether *the acquisition premium* was reasonable . . .."[16] The merger premium was a critical component of the transaction and the Commission was found to have erred in deciding to put off the decision regarding its recovery. Notably, where there were numerous unknown cost impacts associated

[14] The premium constituted 34% of the value of the merger, and a full 20% of the combined cost of service of the combined companies.
[15] In re Missouri-American Water Company, et al., Case No. WM-2004-0122 (Report and Order, issued November 20, 2003, 2003 Mo. PSC LEXIS 1496).
[16] 120 S.W.3d at 736.

with the Aquila transaction involved in AG Processing, the Supreme Court did not require the Commission to consider their speculative rate impacts.

2. The legal standard governing asset transfer cases remains the same.

Staff and OPC also suggest that some other standard, perhaps a "just and reasonable" standard or a "best interests" standard,[17] applies in asset transfer cases. Staff's brief at p. 2; OPC's brief at p. 3. In this instance, it is they who ignore AG Processing. As discussed above, "the standard used to evaluate a merger [asset transfer] subject to approval by the PSC . . . is whether or not the merger [asset transfer] would be 'detrimental to the public.'" AG Processing, 120 S.W.3d at 735 (*citing* State ex rel. City of St. Louis, 73 S.W.2d at 400 and applicable Commission rules).

3. Staff and OPC now seek to disavow this Commission's longstanding asset transfer cases, and cases such as *City of St. Louis* and *Fee Fee Trunk Sewer.*

Staff and OPC argue that the Company "ignores" AG Processing and that the Company's position with respect to its application is "clearly erroneous." Staff's brief at p. 31; OPC's brief at p. 7. OPC says that the Company's arguments that opponents of a transfer must show by compelling evidence a likely direct and present detriment exists (as opposed to speculation about a future detriment) are "absurd." OPC's brief at p. 7. Staff states that it "disagrees with the meaning the some utilities are ascribing to the Supreme Court's decision in City of St. Louis." Staff's brief at pp. 21-22.

The Company's arguments (which OPC says are "absurd"), or the "meaning ascribed" to these well-established cases that were entirely undisturbed by AG Processing, are not a product of *the Company's* making. Rather, these meanings are *based on this Commission's own words*,

[17] We address, and fully demonstrate the fallacy of this "best interest" argument *infra* at Section VI.

and the cases that construe and apply Section 393.190.1.[18] Further, common sense tells us that this Commission cannot speculate about future ratemaking impacts and cannot turn every Section 393.190.1 case into a rate case: "The *Commission* reads *State ex rel. City of St. Louis v. Public Service Commission* to require a *direct and present public detriment*" (emphasis added).[19] The fact that this Commission's duty (and authority) in a Section 393.190.1 asset transfer case does not allow it to deny asset transfers based upon future, speculative rate impacts but rather, based only on known public detriments arising primarily from proven negative impacts on service, is not a concept dreamed up by the Company. Missouri courts have been clear: "The obvious purpose of this provision [section 393.190] is to ensure the continuation of adequate service to the public served by the utility." Fee Fee Trunk Sewer, 596 S.W.2d at 468; *accord* State ex rel. Missouri Cities Water Co. v. Hodge, 1993 Mo. App. LEXIS 1361 (Mo. App. E.D. 1993).[20]

This Commission continues to recognize this purpose in deciding Section 393.190 cases. As pointed out in our initial brief, the linchpin of the only (other than the Missouri-American case) contested Section 393.190 case decided since AG Processing, the Aquila Asset Pledge Case,[21] was that Aquila was asking this Commission to allow it to transfer (more specifically, to pledge as security) *$417.5 million*[22] of essential utility assets that could then be lost to foreclosure. The Commission made particular note of the fact that it was the "financially

[18] Staff apparently not only disagrees with the meaning ascribed to decided cases by the utilities, but also, disagrees with this Commission as well, at least in this case, where Staff wants to extract concessions regarding the JDA.

[19] In re Kansas City Power and Light Company. Accord In re Laclede Gas Company, Case No. GM-2001-342 (Order Approving Stipulation, issued Aug. 14, 2001, 2001 Mo. PSC LEXIS 1099). OPC accuses the Company of misrepresenting the City of St. Louis case. The undersigned counsel wrote the reference OPC complains about, and states herein that there was no intention to mislead the Commission or anyone else. It is this Commission itself, in the Kansas City Power and Light Company case cited at page 9 of Exhibit 69, that cited the City of St. Louis case for the proposition that a direct and present detriment must be presented by those claiming detriment. See also the discussion of these issues at pp. 11-13 of the Company's initial brief.

[20] Staff also tries to distance itself from the Fee Fee Trunk Sewer case, a case cited by, and relied upon by, this Commission numerous times and a case that has not been criticized or limited by any court.

[21] See also the discussion of this case at pp. 54-56 of the Company's initial brief.

[22] A clearly quantified and, particularly for Aquila, large item.

unstable" Aquila that asked for this permission – that financial instability existing today – *presently* – when the pledge was denied. This Commission specifically noted the risk of *loss of service* due to loss of these assets to foreclosure and found that this was a direct and present detriment that warranted denial of the pledge on the rather unique facts of that case.[23] AmerenUE is not in a similar position, nor is the proposed transfer analogous to the Aquila Asset Pledge Case in any way. There is no evidence in this case that substantiates that AmerenUE customers will be worse off with the transfer. Indeed, the opposite is true.

One other argument made by both Staff and OPC in this regard requires a response. They both imply (see Staff's brief at pp. 21-22 and OPC's brief at pp. 8-9) that if the Company is right; that is, if compelling evidence of a direct and present detriment must be shown, then utilities will "game" the system. They allege that utilities will game the system by proposing transfers that are free from initial detriments, but that may be full of later detriments. This argument is just another in a long line of statements that reflect Staff's and OPC's clear lack of confidence in either their own ability, or this Commission's ability, to do their or its job. For decades, this Commission has decided Section 393.190 cases by properly applying the standards of the City of St. Louis and Fee Fee Trunk Sewer cases. For decades, this Commission has properly recognized that Section 393.190.1 primarily seeks to ensure that asset transfers do not negatively affect safe, adequate and reliable service, and that utilities are not allowed to complete transfers if there are direct and present detriments in that regard that are likely to occur. Staff and OPC cite no instance where utilities were able to "game" the system to defer detriments and to in effect "pull the wool over" the Commission's eyes, as Staff and OPC purportedly now fear.

[23] While we allege no impropriety in failing to do so because, after all, these are adversary briefs, we note that Public Counsel makes no mention of the facts in the Aquila Asset Pledge Case or of the Commission's statements that cite the concern that foreclosure of $417.5 million of Aquila assets "could include a loss of service," a concern that no doubt was heightened by Aquila's "financially unstable" condition, which was also noted by the Commission.

The Commission is not stupid or inept.[24] If utilities act as cleverly as Staff and OPC claim, the Company is quite sure that this Commission will not later reward that behavior with rate increases arising from such attempts to game the system.

E. OPC's brief contains numerous overstatements unsupported by the record.

Discussed below are some of these overstatements (and some by Staff as well), but the following statements appearing early in OPC's brief (apparently in an attempt to "set the tone") require a response now. These overstatements are as follows:

1. OPC implies that the proposal to transfer the assets lacks "assurances" that there will be no negative effect on service quality[25] – OPC cites nothing in the record that would support the existence of any such negative effect, because there is none. In fact, the record is contrary.[26]
2. OPC alleges the transfer is designed to benefit American Energy Generating Company ("AEG") and promote retail competition in Illinois[27] – OPC cites no support in the record because there is none.
3. OPC asserts there is "no disagreement" that the transfer will "change the way that electricity is generated for and transmitted to AmerenUE." OPC says the proposal will "break up the vertically integrated structure of AmerenUE."[28] Again, OPC cites no support in the record because there is none.

II. LEAST COST ANALYSIS

The transfer has affirmative benefits, though we need not have demonstrated that such benefits exist to meet our burden in this case.[29] There is no proof, indeed no credible and supported allegation,[30] that the transfer would somehow negatively affect the Company's ability to provide safe, adequate and reliable service. The Company has thus proven its case, and in any

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[24] Nor do we suggest that Staff or OPC are stupid or inept. Rather, we suggest that they desire to opportunistically misuse AG Processing to throw up a myriad of roadblocks in front of the transfer in order to achieve their other regulatory agendas (i.e., SO_2, JDA, EE Inc).
[25] OPC's brief at p. 2.
[26] Ex. 6 at p. 2, l. 7-9 and p. 4, l. 6-19; Tr. at p. 915, l. 6-13; Tr. at p. 1143, l. 5-18; Tr. at p. 1468, l. 13-23.
[27] OPC's brief at p. 3.
[28] OPC's brief at p. 4. We suppose OPC is referring to the transfer of the Illinois transmission assets which likely benefits Missouri to the tune of between approximately $1.5 million to $3 million per year.
[29] In re Sho-Me Power Corporation, Case No. EO-93-259 (Report and Order, issued September 17, 1993, 1993 Mo. PSC LEXIS 48).
[30] OPC has now belatedly made the vague and unsupported claim that somehow the Company has "failed to provide adequate assurances" that the transfer would not negatively affect service. OPC's Initial Brief at p. 2. The record is contrary. FN 26, supra.

event, has presented substantial and competent evidence of substantial benefits. The Company discusses the benefits of the transfer at length at pages 4 and 13-20 of its initial brief. Staff and OPC level several criticisms at the Company's analysis. They do so mostly in the context of seeking JDA and EE Inc.-related concessions while also suggesting that they may seek separate investigations relating to those issues and to the SO_2 allowance issue discussed below, raising the question: why is the Commission dealing with those issues in this asset transfer case? They level these criticisms despite the fact that the analysis done is the very analysis discussed with Staff and OPC in detail relative to discussions about the transfer in January and February 2002.[31]

Another preliminary but important point bears noting. Staff has not argued the analysis is wrong.[32] Rather, Staff suggests that additional analyses ought to be done to provide more "comfort" in the results. Each time more analyses have been done the transfer option ends up looking even better relative to the CTG option than our initial least cost analysis showed (e.g., the Staff's and the Company's transmission analyses). At some point the process of "analyzing the analysis" must cease, and a decision must be made. Commissioner Murray recognized this very point during the hearings during her questioning of Dr. Proctor:

> Q. It appears to me that when we're analyzing something like a proposed transfer such as this, that we could go on for years analyzing what possibly could happen to make the result either weigh in either direction, either detrimental or beneficial to the Missouri ratepayers. And it seems that at some point you should reach a -- a level in which there is enough comfort that it's reasonable, it may go -- you know, it's a possibility, there are always possibilities in the future that things won't turn out exactly as you think they will. But we would never take a step forward if we had to know for certainty how in the future we're going to turn out. So when do we reach that point and how close to it are we here?[33]

[31] Ex. 10 at p. 10, l. 13 to p. 12, l. 16; Tr. at p. 1590, l. 21 to p. 1591, l. 19; Tr. at p. 1687, l. 1 to p. 1688, l. 3.
[32] Tr. at p. 1781, l. 15-16; Tr. at p. 1591, l. 6-19 (Indicating Staff's belief that the transfer is in Missouri's long term interest).
[33] Tr. at p. 1239, l. 11-24.

Dr. Proctor did not directly answer the question, other than to ask for more analysis on the revenue requirement impact of transferring the Illinois transmission assets, analyses that have now been done and that, as we suspected all along, show substantial *benefits* from the transfer. Dr. Proctor also agreed that no amount of analysis will ever allow us to be certain that the results of an analysis are 100% correct.[34]

A. <u>The least cost analysis was conservative and confirmed the Company's prior analyses.</u>

Staff's first "criticism" is that the timing of the final completion of the analysis renders it suspect (Staff's brief at pp. 38-40). Similarly, OPC makes the entirely unsupported allegation that the analysis was designed to reach a "preordained" conclusion. OPC's brief at p. 16. The record refutes these contentions.

This is the third time this transfer has been before the Commission.[35] It was approved in 1997 in Case No. EM-96-149. It is correct that the first time this transfer *was approved* the Illinois transmission assets were not involved, and on that basis this transfer is different. It is also different in another important way: when this Commission approved the first transfer there were *no generation-related savings* for at least ten years due to a power purchase agreement whereby AmerenUE would sell power to AmerenCIPS for supplying the transferred service territory. This transfer offers both generation and transmission-related savings.[36] A transfer of these assets (including transmission) was proposed again in 2000 in Case No. EM-2001-233,

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[34] Tr. at 1239, l. 25 to p. 1240, l. 15. Curiously, Staff alleges that Dr. Proctor testified that the least cost study "would not even meet the requirements of the Commission's least cost planning rules." Staff's brief at p. 6. No such statement appears in the transcript, and there is nothing in the least cost planning rules (4 CSR 240-22.060) that supports that statement or the statement Dr. Proctor made at p. 1773, l. 6-24 of the transcript).

[35] Tr. at p. 367, l. 15-21; Tr. at p. 460, l. 18 to p. 461, l. 1.

[36] Tr. at p. 389, l. 23 to p. 390, l. 2. This Commission approved transfer of these same assets, with the exception of the transmission assets located in Illinois and involved in the current proposal, when the Company's merger with Central Illinois Public Service Company was approved in Case No. EM-96-149. Tr. at p. 531, l. 25 to p. 533, l. 8; Ex. 37, § 10, p. 33. The transfer was not completed at that time because the ICC opposed the transfer due to its concerns about the above-mentioned purchased power agreement between AmerenUE and AmerenCIPS. Tr. at p. 370, l. 17 to p. 371, l. 12. Tr. at p. 533, l. 19 to p. 534, l. 4.

where the Company's testimony indicated that the transfer was the least cost option. The transfer is before the Commission again in this case. It is correct that the least cost analysis submitted in this case was not completely finished at the time the Boards of Directors of the respective companies involved approved the transfer (about three months earlier). But that approval came based upon Mr. Craig Nelson's discussions with the boards at a time when he and the boards knew that the transfer had previously been found (in 2000) to be the least cost means of meeting the Company's needs, and at a time when he and the boards knew that the same conclusion had been preliminarily reached (and discussed at length with Staff and OPC) in early 2002.

Staff is apparently contending that the Company "rigged" the analysis. If the Company wanted to "rig" the analysis, it did a poor job. The Company did not file its Application on the basis of transmission-related savings, yet there is substantial proof that transmission related savings produce an annual benefit of between $1.5 million and $3 million.[37] The Company did not file its Application in reliance on the positive effect future load growth and likely higher natural gas prices would have on the transfer case relative to the CTG case, but those additional savings very likely exist – a fact that no one seriously disputes. The Company, though it has been criticized by Staff for doing so, gave the CTG case the benefit of a mark-to-market analysis which, as discussed further below, makes the CTG option *look better* relative to the transfer case than it otherwise would have looked. Each of the foregoing facts show that, if anything, the Company was conservative in the analysis it performed and that the advantage of the transfer case relative to the CTG case is probably understated, as discussed further below (this very issue is discussed in more detail at pages 14-18 of the Company's initial brief).

[37] See record evidence discussed at p. 9 of the Company's initial brief.

Staff needs to make up its mind. The Company met and worked with Staff in January and February 2002 to develop an accounting based (test year) approach (the very approach used in this case) and reached consensus on the acceptability of that approach.[38] Dr. Proctor doesn't dispute this – he just says he "doesn't recall" it that way.[39] The actual data used in the models developed in collaboration with Staff during those 2002 meetings was of course different by late Summer 2003 when the analysis was actually done, but the same spreadsheet models based upon use of test year data were used. (See footnote 31, supra). The Company considered using forecasted budget and load growth instead of using a test year approach, but believed there were too many uncontrollable factors and that conducting a sensitivity analysis using forecasted numbers would lead to greater speculation.[40] The Company's approach is and remains sound.

B. The sum total of all of the benefits this transfer will produce for Missouri addresses any concern about the "thinness" of the benefits shown by the initial least cost analysis.

Regardless, Staff's ultimate conclusion about the analysis is not that it is wrong, or that the transfer is not the best mechanism to meet the Company's long-term needs. Rather, Staff simply concludes that the $2.4 million of annual benefits relative to the CTG option is "thin," as discussed at pages 42-43 of Staff's brief and as also generally argued by OPC. Even if one assumes that Dr. Proctor is correct – that $2.4 million annually is "thin" – once other evidence of record is taken into account, what was arguably once "thin" becomes rather "fat." There exists substantial and competent evidence of record the $2.4 million that Dr. Proctor indicates is "thin" is more likely to range from nearly $11 million per year to over $30 million per year. An increase in the benefits of that magnitude (i.e. an increase of about $10 million per year), according to Dr. Proctor, would "greatly enhance the economics in favor of the transfer" and

[38] See FN 31 supra.
[39] Tr. at p. 1806, l. 4-9.
[40] Tr. at p. 1604, l. 12 to p. 1605, l. 2.

would "significantly reduce the risk of undetected detriments from the deficiencies of Ameren Services' analysis in this case."[41]

There are numerous such enhancements evidenced by the record, all of which is discussed at pages 13-20 of our initial brief. First, there are substantial transmission related savings (using the most likely cases from both the Company's and Dr. Proctor's transmission analyses) ranging from about $1.5 million to up to $3 million per year. Second, though in the Company's view this is not a necessary condition in this case, if the Commission determines that it will require the JDA amendment offered, there are additional annual benefits of approximately $7 million to $24 million per year that will not occur absent the transfer. Third, though not quantified because it is self-evident, the expected growth in the Company's load will likely produce more benefits in that the costs of the transfer will be spread over a greater number of kilowatt hours of usage. Fourth, though the least cost analysis assumed the cost of the natural gas needed to fuel the CTGs would be only a very conservative $5 per mmbtu, the Company actually expects natural gas prices to be $5.76 per mmbtu, a figure that may itself be too conservative, given that natural gas prices are now over $6 per mmbtu.[42] Because higher natural gas prices make the CTG option substantially less attractive relative to the transfer option, the benefits of the transfer option increase further. Finally, as discussed in more detail below, if the effects of the allegedly improper mark-to-market analysis that enhanced the CTG case with more profits from interchange (off-system) sales are reversed, the transfer case becomes yet more attractive versus the CTG case by another $1.2 million per year.[43] In summary, the record, as reflected in the following table, shows huge benefits from the transfer:

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[41] Ex. 14 at p. 16, l. 10-13; Tr. at p. 944, l. 17-19.
[42] Money and Investment Section, *Wall Street Journal*, June 8, 2004 (showing natural gas future prices for July 2004 on the New York Mercantile Exchange of $6.20 per mmbtu).
[43] Tr. at p. 1689, l. 1-25; Tr. at p. 1618, l. 18 to p. 1619, l. 3.

Annual Savings over CTG Case by Category	**Conservative Case Estimate** (in Millions of $)	**Expected Case Estimate** (in Millions of $)
Generation-related savings from initial least cost analysis	$2.4	$2.4
Transmission related savings	$0.385	$1.5 - $3
JDA amendment	$7.0	$24
Eliminate benefit to the CTG Case arising from mark-to-market analysis	$1.2	$1.2
Load growth	More benefits	More benefits
Expected gas prices	More benefits	More Benefits
TOTAL	**$10.985 plus per year**	**$29.1 to 30.6 plus per year**

C. Though Staff levels several rather minor criticisms at the least cost analysis (see Staff's brief at pages 43-55), Dr. Proctor's testimony demonstrates that the only other material issues revolve around two areas: failure to use forecasting and inconsistency in using the mark to market analysis (see pages 55-57 of Staff's brief).

The Company already addressed both of these areas at pages 27-29 of the Company's Reply to Staff's List of Conditions (Ex. 69). The Company stands by each and every statement made therein, most of which Staff does not take any direct issue. For example, at the first full paragraph on page 46 of its brief, Staff accuses the Company of offering a "poor excuse" for not formally analyzing the effect of forecasted load growth on fuel savings. Staff does not, however, directly dispute the fact that load growth over time will likely increase the fuel savings of the transfer relative to the CTG option given that with the transfer the Company will use its predominantly coal-fired generation versus using natural gas-fired CTGs. This point is quite obvious, unless you seriously believe (and no one alleges that this is the case) that coal will cost more than natural gas over time.

Regarding use of a mark-to-market analysis for the CTG option and not for the transfer option, Staff's complaint is simply that this is "inconsistent" and "arbitrary." Already discussed above is the fact that if the Company had been "consistent" on this point, and not giving the CTG option credit for interchange sales by using the mark-to-market analysis, the transfer option would be superior to the CTG option by another $1.2 million per year (an increase in generation-related savings from $2.4 million to $3.6 million). Addressing "Staff's concern with consistency" (Staff's brief at p. 48) therefore simply provides more, not less, support for the transfer.

In expressing concerns about consistency, about a lack of a transmission revenue requirement analysis, and about the lack of a formal natural gas revenue requirements analysis,[44] it appears that Dr. Proctor is speaking from his standpoint as an academician and an economist. Because not every single theoretical contingency or alternate analysis that could have been addressed was not addressed, does not render the analysis incorrect, nor does it necessitate yet more analyses. The Company and this Commission must view the transfer in the "real world," from a practical standpoint, not from the viewpoint of one engaging in an academic exercise about minor details of the analysis based on an agenda to obtain rate case-related JDA amendments. As discussed above, taking into account all of the benefits (not just the generation-related savings addressed by the least cost analysis), the benefits from completing this transfer are not "thin." Recall again Commissioner Murray's admonition:

> And it seems that at some point you should reach a -- a level in which there is enough comfort that it's reasonable, it may go -- you know, it's a possibility, there are always possibilities in the future that things won't turn out exactly as you think they will. But we would never take a step forward if we had to know for certainty how in the future we're going to turn out.

D. <u>OPC's all-out assault on the least cost analysis does not change the benefits of the transfer for Missouri.</u>

[44] Which is patently unnecessary given that the assets at issue and the customers at issue are solely Illinois assets and customers. Tr. at p. 419, l. 7-14; p. 534, l. 7 to p. 535, l. 1. Staff repeatedly complains about the lack of a "formal" gas revenue requirement analysis, but has yet to articulate any coherent justification for performing a revenue requirement analysis relating to assets and business that are used to serve 18,000 *Illinois* gas customers. The gas situation is unlike the electric side, where Illinois plants (that are not being transferred) and Illinois transmission assets (which, as part of the integrated Ameren transmission system) have been included in rate base for the purpose of setting Missouri rates.

OPC, at times agreeing with Staff and at other times going *much* further than Staff, devotes most of its brief to "recasting" those facets of the least cost analysis with which OPC disagrees, resulting in OPC's "ultimate conclusion" that the CTG option would be cheaper than the transfer option by a mere $100,000 per year. That figure, even if it were accepted *for the sake of argument*, ignores the non-generation related benefits of the transfer option ($1.5 million to $3 million from transmission savings), the $1.2 million of additional benefit if we remove the mark-to-market analysis to achieve consistency, as Staff advocates, and the $7 million to $24 million annual benefit arising from the JDA amendment offered in this case. A critical look at OPC's theory, including an entirely new one cooked-up just for its brief, undermines OPC's position in any event.

1. OPC uses "fuzzy math" to manufacture a grossly overstated effect of future capital expenditures on the Company's rate base.

A good example of the almost boundless lengths OPC is willing to go to defeat the transfer is reflected on page 21 of OPC's brief. OPC bases this new argument on the "preliminarily estimated" future capital costs for various environmental compliance capital projects that might have to be completed over the next 10-15 years. OPC argues that those capital costs will increase the Company's rate base enough to require $5.1 million to $7 million more in revenue per year. OPC's fuzzy math in reaching this "conclusion" is misleading.

OPC assumes that the *only* change in the Company's rate base over the next 10-15 years will be the result of capital improvements for environmental compliance, and assumes that those improvements will total from about $0.8 billion to just over $1 billion. OPC completely ignores that before (by 2006) any of those capital expenditures would be made, if they are made at all, the Company will have to invest between $2.25 billion to $2.75 billion by the end of 2006 as required by this Commission's Order in Case No. EC-2002-1 (Ex. 35). OPC also completely ignores that the rate base it uses to come up with its misleading figures is only the production – the generation – rate base, and leaves out the rest of the Company's entire rate base which totaled, as of September 30, 2001, $4.137 billion.[45] Adding at least $2.25 billion by 2006 means the rate base (exclusive of depreciation)[46] will total nearly $6.4 billion.

Thus, even if one assumes (an invalid assumption to be sure) that $1 billion is spent on these compliance-related capital improvements *all at once*, for example, by 2006, the "increase" in rate base that OPC argues would only be about 15% (from $6.4 billion to $7.4 billion), not the misleading 58% to 81% argued by OPC. The record reflects that if the "preliminarily estimated capital costs" into which OPC puts so much stock are incurred, they will be incurred over the next couple of *decades*, thus further reducing the impact on the rate base and thus any possible impact on the annual revenue requirement associated with the rate base. This Commission no doubt understands that even a billion dollars invested over a long period of time is not really a billion dollars in rate base or rates, but is something much less than that. No one knows what costs will fall in a test year, whether they will be normalized or allowed in whole or in part, or what the effect of regulatory lag will be.

While the foregoing demonstrates that OPC's *theory* of an additional $5.1 million to $7 million is misleading and suspect, if one *assumed* (but the Company certainly does not concede) that OPC was correct, and if one assumes further that AmerenUE gains not a single additional

[45] Accounting Schedule I in Ex. 75 (Staff's Accounting Schedules in EC-2002-1).
[46] If we assumed that the capital expenditures OPC focuses on would be made between now and 2015, the Company's load will have grown by then by about 25% (based upon the Company's expected 2% annual growth in its load), no doubt necessitating substantial capital investment to keep up.

electric customer between now and 2015, the effect on electric rates would only be about $6.54 *per year per customer (or $0.54 per month)*, or an increase of a mere .0035 (0.35%).[47]

2. **<u>The issues relating to whether the Company will or will not have enough SO_2 allowances to cover its future needs, whether the Company is in compliance with Commission orders relating to SO_2 allowances, and what environmental-related capital investments the Company may or may not make over the next couple of decades, do not belong in this case.</u>**

OPC (and perhaps Staff) accuses the Company of violating this Commission's Order in Case No. EO-98-401 by selling too many SO_2 allowances and contends that the Company therefore may not later have enough allowances to meet its needs. *If* the Company ran out of allowances, *if* allowances are still useful, and *if* regulations required a reduction in emissions, *then*, they argue, the Company's generation costs (relating to the 6% of the total portfolio of AmerenUE plants now available to Missouri) will increase. They allege this is a detriment of the transfer and is a potential flaw in the Company's least cost analysis.

With regard to compliance with Commission orders, the Company testified, under oath, that it is in compliance.[48] Neither Staff nor OPC have gone on record otherwise; they simply "suggest" that the Company might not be in compliance, and they both apparently advocate a *separate* investigation on this issue. The Company takes very seriously its obligation to comply with Commission orders, but as Commissioner Murray's discussion with Mr. Kind demonstrated,[49] if one were to assume *purely for argument's sake* that the Company was in violation of the Commission's order regarding management of SO_2 allowances, there is no way the Commission will reward the Company for violating the order. Thus, such a violation, if it existed, would not harm ratepayers. That alone removes this issue from this case.

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[47] Based upon AmerenUE's current 1.2 million electric customers less the 130,000 Illinois customers to be transferred to AmerenCIPS ($7 million/1.070 million customers).
[48] Tr. at p. 886, l. 12-21.
[49] Tr. at p. 649, l. 19 to page 650, l. 12.

Once again, Staff and OPC invite the Commission to speculate. Mr. Rick Campbell indicated that "a lot of speculation" would be necessary in order to determine the degree of detriment Staff and OPC claim may exist.[50] To figure that out, one would have to predict what environmental laws and regulations will or will not be enacted or repealed or amended over the next 25 years. To predict that, one probably needs to be able to predict whether John Kerry or George W. Bush will be President when January 2005 arrives, who will be President (or control Congress, or both) over the next 20-plus years, the extent to which world events affect energy choices, changing technologies, etc. Mr. Campbell himself testified that the Commission will have a "more secure hold" on these issues in a future rate case.[51] The clear conclusion to be drawn from his testimony is that the Commission has no business speculating about unknown and future costs (and unknown and future rate impacts) today.

The same speculation regarding SO_2 allowances that Mr. Campbell candidly recognized exists is precisely why the Company did not plug costs relating to future environmental compliance into the least cost analysis. The Company did consider[52] the impact of environmental compliance costs, but concluded that the nature and extent of the costs and the effect those costs could have on the revenue side of the equation created too many variables that

[50]Tr. at p. 623, l. 6 to p. 624, l. 14.
[51]Tr. at p. 620, l. 14 to p. 621, l. 5.
[52] OPC's statement (OPC's Brief at p. 18) that Mr. Moore "acknowledged" that environmental compliance costs were not included in the analysis is incomplete. The rest of Mr. Moore's statement (Ex. 21 at p. 2, l. 4-14) makes clear there is no reliable "number" that could be "included" without engaging in much speculation about what environmental regulations will or will not exist. The record in this case reflects that speculation. By far, the single biggest "environmental compliance cost" OPC in particular spends so much time talking about might arise from the New Interstate Air Quality Rule discussed by OPC at the bottom of page 19 and at page 20 of OPC's brief. The Rule was not proposed until after the least cost analysis was done (December 2003), and the 10-K was prepared shortly thereafter. As the Ameren 10-K so heavily relied upon by OPC provides, however, these newly proposed rules "may change" and the estimates in the 10-K are *"preliminarily estimated* capital costs" based on current technology. We do not know if the rule will become law, what its final form may be if it does become law, what capital expenditures may or may not be, or what technology may or may not provide for if capital expenditures must be made.

injected more, not less uncertainty, into the analysis.[53] Therefore, the Company determined that the most accurate way to perform the analysis was to simply assume that the net differential between the transfer case versus the CTG case will remain constant.[54] That is, to assume that if one cost or revenue item which was included in the test year changes, the change will be roughly offset by another item, with the net differential between the two options to remain constant. An example illustrates the common sense behind this approach.

As discussed in detail at pages 38-39 of the Company's our initial brief, environmental regulations could become substantially more restrictive in the future and this in turn could cause SO_2 compliance costs to increase. If that happens, SO_2 allowances might be worth much more than they are today and it would thus take less allowances to realize the same revenues.[55] The exact opposite could be true, and SO_2 allowances could become worthless. In the latter case, hindsight would show that the Company should have sold still more allowances to realize revenues for itself (and ratepayers), a fact that no doubt would be pointed out with vigor by OPC and Staff. Even if the Company at some point has no more SO_2 allowances,[56] common sense indicates that if the regulatory environment drives up compliance costs in the future, those higher compliance costs would also drive electricity prices higher as well. Higher electricity prices would in turn generate more profits from interchange sales and those profits would provide funds toward investing in the capital improvements that may be required, such revenues thus offsetting

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[53] Tr. at p. 1686, l. 4 to p. 1687, l. 22.
[54] Tr. at p. 1604, l. 8 to p. 1605, l. 2; Tr. at p. 1687, l. 18-22.
[55] Take the following example. The least cost analysis assumed an SO2 allowance price of $176 per ton. The price was approaching $300 per ton at the time of the hearings. To realize $17 million in revenues at $176 per ton would require a sale of about 96,000 tons of allowances, but at $300 per ton, would require only about 56,000 allowances, a drop of more than 40%. Or the exact opposite could occur. SO2 allowances might become worthless if, for example, Mr. Kerry becomes President and a "command and control" emission control regime is instituted that simply requires a vast reduction in emissions and does away with using allowances instead. The point is that no one knows what the facts will ultimately be, thus proving the point that we cannot and should not try to speculate about those facts today.
[56] Today the Company has one of the largest banks in the country.

higher compliance costs. Who knows, higher compliance costs at coal-fired plants might force some smaller coal-fired plants out of business which might lead to more demand for gas peakers or otherwise make the Company's proven coal-fired fleet more valuable. The most basic of economic principles hold that more demand for gas peakers would drive-up demand for natural gas, thus increasing its price. So, while a company like AmerenUE might have to spend more on environmental compliance costs at its coal-fired plants, that may be a cheaper long-term option than if it had built more CTGs because CTGs, and the fuel to run them, may also be much more expensive.[57]

The point is that the Company (nor can anyone else) cannot predict any of this with any reasonable level of certainty. That is precisely why numbers reflecting these contingencies (that by definition would have been speculative) were not plugged-into the least cost analysis.[58] The approach advocated by OPC and, to a lesser extent, by Staff, that is, to try to isolate and forecast environmental compliance costs without being able to figure out the effect on the revenue side of the equation is itself flawed and speculative. At bottom, OPC's isolation of this one item – on the cost side of the equation only – and OPC's allegation that this one isolated cost item reduces the generation-related benefits of the transfer by about \$0.7 million per year (from \$2.4 million to \$1.7 million), is the very kind of "inconsistency and arbitrariness" that Dr. Proctor has told the Company it should not do.

Though minor in dollar impact, OPC's other "theory" regarding the effect of the "SO_2 issue" on the least cost analysis also fails to withstand scrutiny (OPC's brief at pp. 27-28) and again illustrates the boundless lengths OPC will go to try to falsely undermine the least cost analysis. OPC went to much trouble to have Mr. Voytas agree that his least cost analysis was in

[57] Will it be only \$5 per mmbtu, as the analysis assumed, or \$5.76 per mmbtu, as was estimated a few months ago, or \$6.20 per mmbtu, as it traded on the NYMEX yesterday? See also Tr. at p. 1607, l. 19 to p. 1608, l. 22.
[58] Tr. at p. 1604, l. 12 to p. 1605, l. 2.

error by $283,000 because of an alleged failure to consider the income tax effect of the SO_2 revenues included in the least cost analysis. Mr. Voytas ultimately "agreed" (based upon the assumption that counsel's assumptions inherent in his questions were correct) that perhaps the benefits shown by the least cost analysis would need to be adjusted downward by $283,000. Mr. Voytas's instincts that there might be a problem with counsel's assumptions and that he might be mistaken in agreeing on this point were correct.[59] OPC's theory is that the $7 million normalization adjustment in SO_2 allowance sales revenues made by Mr. Voytas would increase AmerenUE's net income by $7 million, but that AmerenUE failed to include the income taxes generated by that $7 million of revenue and, therefore, the benefits of the transfer option are overstated by the amount of those taxes – by $283,000.

OPC's premise is incorrect. OPC's theory ignores a basic principle of cost-of-service ratemaking: if the Company receives $7 million in revenues from sales of SO_2 allowances, that $7 million will meet a part of the Company's revenue requirement for ratemaking purposes. Thus, that $7 million *from third parties* will offset – reduce – by $7 million, the revenues the Company will receive *from its* ratepayers. The effect on the Company's net income is therefore *zero*, unless one assumes that this Commission will ignore $7 million of revenue the Company receives from third parties for SO_2 sales. Perhaps this is just another example of OPC's apparent assumption that this Commission will fail to do its job by taking into account *all* of the Company's costs and revenues in setting future rates.

In short, the Company properly used a test year approach, declined to inject perhaps the most speculative variable it could have chosen into its least cost analysis, and instead focused on the items that were most important. The Company properly assumed that the relative difference between the transfer and CTG options would remain relatively constant. That approach is not

[59] Tr. at 1656, l. 22 to p. 1657, l. 5; p. 1157, l. 22-23.

based on speculation, but rather, on actual data focused on the most important elements of the analysis.

3. <u>Everyone except Mr. Kind has concluded that the use of $471/kW as the assumed price of new CTGs in the least cost analysis is appropriate.</u>

OPC next takes issue with the price for construction of new CTGs used by the Company in its least-cost analysis, alleging that the $471/kW figure was "inflated." OPC's brief at pp. 28-29. No one else holds that view. First, Dr. Proctor addressed this issue in his testimony (Ex. 15 at p. 6, l. 22 to p. 10, l.11), a part of which (omissions are noted by ***) is quoted below:

> **Q. What is Mr. Kind's position regarding the $471/kW cost assumed by AmerenUE as a minimum cost alternative to the Metro East transfer?**
>
> A. Mr. Kind's position is that $471/kW is too high. * * *
>
> **Q. What is your analysis of the $390/kW estimate from Case No. EA-2000-37?**
>
> A. * * * Moreover, based on the costs paid by Ameren for the combustion turbines at Kinmundy and Pinckeyville [$471/kW], the issue raised by Mr. Kind appears to be: why didn't AmerenUE assume that 597 megawatts of capacity would all be built in the larger unit size at a lower per kW cost? There are several reasons that this might not be an optimal configuration. The smaller General Electric units at Pinckneyville have significant operational advantages over the larger Westinghouse units at Kinmundy. The smaller units have greater flexibility for quick starts than the larger units. The LM-6000 units at Pinckneyville, even though they are smaller, have better heat rates than the larger units at Kinmundy. Perhaps the greatest advantage to the smaller combustion turbines is the ability to bring them on line in sequence to meet changes in load. Combustion turbine heat rates (efficiencies) tend to be very poor unless the units are run at or near capacity. If load is increasing by less than the capacity of a large combustion turbine, then the utility has to back down cheaper generation in order to run the combustion turbine at a reasonable heat rate level. Smaller units offer greater flexibility in being able to bring fewer megawatts on line to match increased load without having to back down cheaper generation.
>
> The average cost of this combination [$471/kW] and the average heat rate is what AmerenUE used as the combustion turbine alternative to the Metro East Transfer. AmerenUE apparently used an average of larger and smaller units to provide a combination of both the cheaper cost of the larger units and the greater flexibility of the smaller units, replicating the engineering design of what it had installed at Kinmundy and Pinckneyville in the recent past. While I am not aware of any study performed by AmerenUE to determine the "optimal" combination of these characteristics, as an economist I understand the design principles that would be involved.
>
> **Q. Do you have other sources of information to confirm that AmerenUE's cost/kW for combustion turbines is reasonable?**
>
> A. In the resource planning meetings that the Staff and the Office of the OPC have with the utilities, we regularly receive estimates of the costs of combustion

> turbines. Those costs vary depending on the type of combustion turbines that the utilities want to install to fit the operating conditions they expect for use of these units. While there are some exceptions, these estimates are generally consistent with what AmerenUE has paid for both its larger combustion turbine units at Kinmundy and its smaller combustion turbines at Pinckneyville.

Mr. Matthew Wallace's testimony is also clear: \$471/kW is a reasonable proxy for the mix of CTG types the Company will need in the future.[60] After a hotly-contested FERC proceeding involving the Company's acquisition of the Pinckneyville and Kinmundy CTGs for that same \$471/kW price, FERC ALJ Carmen A. Cintron recommended approval of the acquisition, at \$471/kW, finding there was no affiliate abuse involved in the sale and that the sale at \$471/kW, and that the acquisition was consistent with the public interest. Specifically, Judge Cintron found that AmerenUE's purchase is on terms similar to *any other competitive alternatives that are available.*

OPC splits hairs, however, by arguing that Mr. Voytas's testimony in FERC Docket No. EC03-53-000 (Ex. 85) is inconsistent with use of \$471/kW in the least cost analysis. OPC's citation at page 29 of its initial brief is misleading because OPC fails to note that the passage from Mr. Voytas's testimony relied upon by OPC was his response to a question about the investment made by NRG in its Audrain County, Missouri plant for the *heavy-frame* CTG purchased by NRG in Audrain County in 2002. The least cost analysis uses what is undisputed to be the weighted average costs of the *Pinckneyville and Kinmundy CTGs*, \$471/kW, for a *mix* of cheaper heavy frame machines *and* much more expensive (and useful) aero-derivative machines, a transfer this Commission has supported as consistent with its Order in EC-2002-1 and has twice supported with letters to the FERC.[61] As Mr. Wallace's testimony, and that of Dr.

[60] Ex. 22 at pp. 6-8.
[61] Tr. at p. 364, l. 25 to p. 365, l. 16.

Proctor quoted above, make clear, a "CTG is not a CTG."[62] The Company would not meet its resource needs, if it were to pursue CTGs in lieu of completing the transfer, with only the cheaper heavy frame CTG's like the NRG plant to which Mr. Voytas was referring in the FERC testimony taken out of context by OPC. Rather, the Company would use a mix of different CTG types, much like the mix reflected by Pinckneyville and Kinmundy which, on average, everyone except Mr. Kind believes are reasonably valued at $471/kW.

4. AmerenUE's use of its established 17% reserve margin for long term resource planning is not only appropriate, but is prudent.

OPC (at page 30 of its brief) attempts to further "chip away" at the least cost analysis by implying that the Company should have used only a 15% reserve margin in its analysis.[63] Just as OPC advocates use of a mechanism to evaluate *short-term* energy and capacity needs (an RFP) even though the transfer is designed to meet a *long term need*, OPC argues that the Company should use a very minimal planning reserve suited for the short term, but not for the long term.

The Company uses a 17% reserve margin when it does *long-term* planning.[64] MAIN's recommended range for planning reserves is 16% to 19%, so the Company's long-term number

[62] Ex. 22 at pp. 3-6.

[63] Staff also mildly attacks the Company's use of a 17% reserve margin in its brief (it did not do so in any of its testimony), pointing out that failure to meet the reserve margins would not impose a financial penalty on the Company. Staff's brief at p. 51. First Energy almost certainly feels adequately penalized, or at least feels exposed to significant liability, as a result of the severe financial effects of the August 14 blackout, whether or not First Energy's reliability authority levied some kind of fine or "penalty." Is Staff seriously contending that the long-term 17% reserve planning margin the Company has used for years (without complaint from Staff) is inappropriate or that it should not err on the side of caution in establishing reserves?

[64] Tr. at p. 860, l. 12-17. <u>See also</u> Voytas Cross-Surrebuttal Testimony, Case No. EC-2002-1, p. 2, l. 9 to p. 3, l. 4: "**Q. Ms. Hu states that AmerenUE is "also conducting studies that advocate increases in generation reserve margins to ensure system reliability." Ms. Hu implies that this may lead to increases in the cost of service that is to be shouldered by the utility's customers. Please comment.** A. The MAIN Board approved a **minimum** long-term planning reserve margin of 17 to 20% based on engineering reliability criteria. At the suggestion of the Missouri Public Service Commission staff, AmerenUE embarked on a groundbreaking study of optimum planning reserve margins from an economic perspective. The purpose of this study was to take an economic perspective in establishing an optimum planning reserve margin for Ameren over a 10-year planning horizon. Generally speaking, when reserve margins are low, the utility is more likely to purchase from the wholesale market and less likely to sell to the wholesale market. The goal of this study was to determine whether increasing or decreasing the Ameren reserve margin over a broad range of uncertainty factors would increase or decrease the present value of net generation costs to Ameren. The reserve margin that minimized the present value

is in fact below the midpoint of that range. Incredibly, OPC, because it suits its arguments in this case, advocates that AmerenUE use a short term reserve planning margin in an analysis of resource needs over a 25 year period!

5. <u>OPC misstates the Company's capacity position.</u>

OPC is alone in arguing that the Company does not and will not need anywhere near as much energy and capacity as the record reflects as needed. OPC bases this argument on Mr. Kind's Attachment 2. Dr. Proctor's testimony (Ex. 15, p. 2, l. 3-24), part of which is quoted below, discredits Mr. Kind's numbers:

> **Q. What is Mr. Kind's rebuttal testimony regarding the capacity balance position of AmerenUE if the Metro East Transfer takes place?**
>
> A. This is shown on Attachment 2 to Mr. Kind's rebuttal testimony. Mr. Kind testifies that numbers in this Attachment show there is no need for the capacity that AmerenUE would have after the proposed Metro East transfer.
>
> **Q. Do you agree with Mr. Kind's analysis and conclusions?**
>
> A. No, I do not. * * * Thus, the asserted lack of capacity need is, by itself, not a viable argument for detriment.

The correct capacity position is reflected in the tables shown on page 7 of the Company's initial brief (HC version).

E. <u>The Company was mistaken with regard to one aspect of the least cost analysis as it relates to the CTG option.</u>

OPC's last major criticism, appearing at the bottom of page 31 and the top of page 32 of OPC's brief, is well taken, though it does not affect the outcome of the least cost analysis or change the fact that the transfer is beneficial to Missouri. As discussed above, the Company did a mark-to-market analysis for the CTG option which gave the CTG option credit for interchange

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of net costs was selected as the optimum planning reserve margin. The study confirmed that a minimum planning reserve margin of **17%** minimized the present value of net costs to Ameren and its customers. As explained later in my testimony, our reserve margin information is being marked Highly Confidential."; <u>See further</u> Voytas Direct Testimony, FERC Dk. No.EC03-53-000, p. 2, l. 37-42: "As a member of MAIN, AmerenUE must meet certain minimum short term and long term planning reserve margin requirements, which are currently 15% for 2003 and 17% for 2006, respectively."

sales based upon forecasted gas and electricity prices. That mark-to-market analysis added $1.2 million of benefits to the CTG case. Had the Company been consistent as Dr. Proctor advocates, that $1.2 million of advantage for the CTG case would not have existed, thus increasing the relative advantage of the transfer case over the CTG case from $2.4 million to $3.6 million per year. As OPC points out, the Company also inconsistently (though consistent with the mark-to-market analysis) escalated the operating and maintenance costs for the CTG option by 2% per year, but did not escalate the costs for the transfer option. That was a mistake, and it does overstate the cost of the CTG option relative to the transfer option by about $800,000 per year. That $800,000 cost, therefore, offsets the $1.2 million in benefits of the CTG option created by the mark-to-market analysis discussed above, resulting in a net increase in the relative benefit of the transfer case of $400,000 versus $1.2 million, meaning the relative advantage of the transfer case over the CTG case from a generation-related savings perspective would not increase to $3.6 million per year, but instead increase to $2.8 million per year.

While OPC has a valid criticism with regard to the 2% escalation of O & M costs for the CTG option, OPC's other "corrections" shown on page 33 of its brief do not withstand scrutiny. Accepting OPC's valid criticism results in the following net benefits from the transfer:

Annual Savings over CTG Case by Category	**Conservative Case Estimate** (in Millions of $)	**Expected Case Estimate** (in Millions of $)
Generation-related savings from initial least cost analysis	$2.4	$2.4
Transmission related savings	$0.385	$1.5 - $3
JDA amendment	$7.0	$24
Eliminate benefit to the CTG Case arising from mark-to-market analysis/eliminate 2% O & M escalation	$0.4	$0.4
Load growth	More benefits	More benefits
Expected gas prices	More benefits	More Benefits
TOTAL	**$10.185 plus per year**	**$28.3 to 29.8 plus per year**

III. THE JOINT DISPATCH AGREEMENT ("JDA")

A review of pages 55 to 72 of Staff's brief reveals that Staff does not rebut in any material way any of the points made by the Company at pages 22-26 of the Company's initial brief with regard to Staff's proposed JDA conditions. Staff's brief at page 72 in fact acknowledges that "the Company's offer to amend the JDA does improve the economics of the proposed transfer . . .." Staff is not satisfied, however, primarily because the Company is not at this point willing to make the second amendment to the JDA Staff wants: changing the pricing of energy transfers between AmerenUE and its affiliates from pricing at incremental cost to pricing at market, specifically, the market price to later be established by the MISO's Day 2 markets. Dr. Proctor himself perhaps best sums up why the JDA is not a necessary and essential issue in this case (Tr. at p. 919, l. 1-9):

Q. It's a dollars and cents issue for you?
A. That's correct.
Q. And as a result, this is an item that's ordinarily addressed in a rate case. Correct?
A. It would be addressed in a rate case, yes.
Q. And you expect that it will be addressed in the next rate case?
A. If the Joint Dispatch Agreement doesn't change, it will be, yes.

The JDA issue is a pure ratemaking issue that, under the facts and the law, has no place in this case.[65]

The following briefly summarizes the Company's position on the JDA, as discussed in more detail at pages 22 to 24 of the Company's initial brief:

1. While the Company does not agree with Dr. Proctor's conclusion that only $3.7 million to $12.68 million[66] (Staff's brief at p. 70) of the annual benefit arising from the amendment we have offered is on account of the transfer, the fact

[65] Staff all but concedes this point in advocating for a separate "investigation." Staff's brief at p. 13.

[66] Dr. Proctor contends that only $3.7 million of the conservative $7 million (52.8%) of benefit the Company claims the JDA amendment it has offered will bring arises "from" the transfer. The Company's evidence is that the more likely expected benefit is $24 million per year; thus, if for argument's sake one accepts Dr. Proctor's contention that only 52.8% of the benefit arises from the transfer, the annual benefit from the transfer would still be a substantial $12.68 million per year (52.8% of $24 million).

remains that even this is a substantial benefit that, without the transfer, will not occur.

2. Staff can attempt to argue to the contrary all day, but the record is clear: these JDA issues *were settled* when Staff and OPC put their signatures on the Stipulation and Agreement in Case No. EC-2002-1, a Stipulation approved by this Commission. Staff is attempting to re-trade that deal. Staff unconvincingly tries to rationalize this inescapable fact away (see pages 64-68 of Staff's brief). The record, cited by Staff, refutes that attempt given that Dr. Proctor himself testified that "everything was resolved" and agreed with Judge Thompson that "everything was settled."[67] True, Dr. Proctor and Staff contend the JDA issues were "not fixed," and it is true that future ratemaking issues relating to the JDA were not resolved. But the fact remains that Dr. Proctor submitted testimony in that case on *both* of the JDA amendments Staff advocates as conditions in this case, and with regard to one of the amendments, actually proposed a specific dollar adjustment to the Company's revenue requirement. Staff does not dispute any of this. Staff is also incorrect in arguing that somehow the Company's contentions in this regard "violate" the EC-2002-1 Stipulation. Paragraph 14.a of the Stipulation simply provides that there has been no agreement on ratemaking, a point we just made above. Paragraph 14.b simply provides that *if the Commission does not approve the Stipulation and* Agreement, no one will be bound by it. The Commission *did* approve the Stipulation – and we are all bound by it.

3. If Staff and the Company do not or cannot reach agreement on the remaining JDA issues by the time of the Company's next rate case, the JDA "will be an issue" and Staff can and will make all of its arguments and propose all of its adjustments, at that time – nothing is stopping Staff from doing so.

4. Despite Dr. Proctor's expression of confidence in MISO, we do not have today, and will not have on December 1, 2004, a MISO Day 2 market necessary to implement the other amendment Staff wants. We thus will have no experience with such a market until, at the earliest, well into 2005, if then. The MISO filed its first Day 2 tariff in July 2003 and then withdrew it, delaying implementation of its Day 2 markets.[68] The MISO came back with another tariff filing on March 31, 2004, planning to implement the Day 2 Markets on December 1, 2004 – 17 months after its first try.[69] On May 26, 2004, another delay occurred – pushing the supposed start date back to March 1, 2005.[70]

[67] Tr. at p. 923, l. 20-23.
[68] See the history of MISO's Day 2 markets discussed at ¶ 7 of the FERC's Order Accepting and Suspending Tariff Sheets, Etc., 107 FERC ¶ 61,191 (May 26, 2004).
[69] Id. at ¶ 9.
[70] Id. at ¶¶ 3-4 .

IV. ELECTRIC ENERGY INC. (EE Inc.)

OPC remains fixated on EE Inc. Staff's brief, in direct contradiction to Dr. Proctor's sworn testimony, mildly seeks to jump on OPC's bandwagon on this issue.[71] Dr. Proctor's sworn testimony contradicts Staff's belated litigation position on this issue, and demonstrates that EE Inc. is not an issue in this case.[72] A portion of Dr. Proctor's testimony in this regard follows:

> "Q. **Does Mr. Kind attempt to link the need for capacity to the termination of the contract between AmerenUE and EEI for capacity and energy from the Joppa generation plant?**
> A. Yes, he does. * * *
>
> Q. **Do you agree with Mr. Kind that the generation capacity from the Metro East transfer would not be needed if the EEI contract is renewed?**
> A. No, I disagree with this conclusion. * * *
>
> Q. **Assuming there is no Metro East transfer, what impact does the expiration or continuation of the EEI contract have on AmerenUE's capacity needs?**
>
> A. * * * In my opinion, the Metro East transfer is not dependent upon the expiration or continuation of the EEI contract, and the continuation of that contract should not be a necessary condition for Commission approval of the Metro East transfer."

The record is clear: the only expense that is and has been included in the Company's cost of service for ratemaking purposes relating to EE Inc. are the dollars the Company paid EE Inc. to purchase power.[73] That expense is no different than power purchase expense from any other seller of power.

OPC (p. 45 of its brief) also mixes apples and oranges in attempting to equate the Company's commitments not to freeze out a minority EE Inc. shareholder, Kentucky Utilities ("KU"), with OPC's contention that this Commission should force the Company to force EE Inc. to sell power to the Company at cost forever.[74] Under Illinois law (which controls corporate governance issues for EE Inc., an Illinois corporation), majority shareholders bear the burden to

[71] See Staff's initial brief at p. 128; Staff's List of Conditions at p. 14.
[72] Ex. 15 at p. 3, l. 3 to p. 4, l. 10.
[73] Tr. at p. 1579, l. 1-18; Tr. at p. 1767, l. 7-22; Ex. 7 at p. 10, l. 10 to p. 11, l. 8.
[74] Mr. Nelson succinctly explained this very point. See Tr. at p. 1565, l. 17 to p. 1566, l. 15.

prove the fairness of their actions -- the minority shareholder need not prove that the actions were not fair. See, e.g., Shlensky v. South Parkway Building Corp., 19 Ill.2d 268, 166 N.E.2d 793 (1960). Certain duties are owed to the minority shareholder by the majority shareholder. 10 *Illinois Jurisprudence* § 6.15 (2002). In recognition of those principles, Ameren made a commitment that it would not freeze out KU. The forced-sale OPC advocates is in fact precisely the kind of transaction that may put the majority shareholder in the position of being accused of unduly favoring its own interests to the detriment of minority shareholders. If EE Inc. is forced to sell power to AmerenUE at cost versus at some other fair price, KU will lose its 20% of the benefit that selling the power at a fair price would bring EE Inc.

Make no mistake, OPC wants that power at the lower of cost or market. *See* Motion to Intervene, Protest and Request for Hearing of the Missouri Office of Public Counsel, In Re Ameren Corporation, FERC Docket No. EC01-81-000 (which is Ameren's FERC case involving Ameren's proposed acquisition of Illinois Power Company), at p. 6. That pleading makes absolutely clear that OPC's assertion, at page 15 of its brief, where it accuses Mr. Nelson of raising a "red-herring" with respect to the affiliate transaction rules, is disingenuous. As Mr. Nelson suspected, OPC's Protest at FERC confirms that OPC has absolutely no intention of ever supporting a waiver of the affiliate transaction rules that might allow EE Inc. and AmerenUE to arrive at a fair deal for power.[75] Mr. Nelson didn't raise a red-herring; he called a spade a spade. In short, OPC (and apparently Staff, now having jumped on this bandwagon contrary to Dr. Proctor's sworn testimony) is never going to support a waiver of the affiliate transaction rules and wants this power at cost. In the end, though, EE Inc. will not sell power to AmerenUE at cost. AmerenUE is in no position to force it to do so to the detriment of not only KU, a minority EE Inc. shareholder, but also to the detriment of Ameren Corporation and its shareholders (the

[75] Tr. at p. 543, l. 11 to p. 544, l. 24.

investing public), of AEG, and to the detriment of AmerenUE's preferred stockholders (also the individual investing public).[76] It is quite possible any such contract would not gain approval at FERC in any event.[77] Nor does this Commission have the authority to take over AmerenUE's management and force AmerenUE to force EE Inc. to do so.

V. LIABILITIES

Pages 84 to 94 of Staff's brief addresses what Staff views as the "liabilities" issue. There is little to say on this issue that the Company has not already addressed at pages 26-36 of its initial brief, but some commentary is necessary herein.

A. The Company is not required to become an "insurer" for ratepayers.[78]

Staff's opening salvo is to pick up on Dr. Proctor's "insurance" theme and argue Staff has a "better solution": "insure against" these liabilities.[79] Staff's brief at p. 84. As pointed out in the Company's initial brief, the principal item[80] Staff argues ought to be insured against are future *capital expenditures* relating to possible environmental compliance needs that *Dr. Proctor himself did NOT include in the occurrences for which he was looking for insurance.* Company's initial brief at pages 33-34.

B. Staff's adversary brief misstates the record.

Staff follows up its "insurance" theme with numerous misstatements. First, Staff (without citation to any authority) argues that there is a "likelihood" of "potentially huge, personal injury, property damage or environmental cleanup liabilities." Staff's brief at p. 85; See

[76] See Tr. at p. 1571, l. 15-19; p. 1574, l. 3-13; and p. 1577, l. 17 to p. 1578, l. 15, which reflects the fact that AmerenUE has holders of preferred shares of stock who are members of the general public to whom AmerenUE owes duties, including the duty to act fairly and reasonably for them in seeking a fair return on its EE Inc. stock, stock which was bought and paid for not by any Missouri ratepayers, but by the shareholders of AmerenUE.
[77] Tr. at p. 1585, l. 10-22.
[78] "Q. So we are not in the business of insuring ratepayers against calamity? A. I agree." Tr. at p. 1794, l. 2-4.
[79] In its brief, Staff uses the term "assurance" or its derivatives about 30 times, "insure" or its derivatives more than 15 times, and advocates for "hold harmless" commitments or "guarantees" many more times.
[80] See, e.g., Staff's brief at pp. 91-92.

also Staff's brief at p. 88 (stating that these things are "likely"). There is not a scintilla of evidence in this record that supports the "likelihood" of such liabilities. In any event, Staff conveniently fails to point out that the *only* possible exposure of Missouri ratepayers arising from the transfer would be *6% of those liabilities in excess of already established reserves*. Staff boldly asserts (without citation to any support in the record) that it "*know[s]* these liabilities will happen" (emphasis added). Staff's brief at p. 88. The clairvoyance demonstrated by Staff's brief (if it were only true) is indeed impressive, yet in the very next sentence Staff itself cites (but apparently ignored) Dr. Proctor's testimony, which the Company quoted at page 37 of its initial brief. Dr. Proctor makes clear he certainly did not "know" that these things will happen. Instead, Dr. Proctor testified that he *could not put a probability on these occurrences,* that they may in fact have a "small probability of happening," and then he concluded his remarks by indicating Staff nevertheless wants some "insurance." As an aside, AmerenUE is not certain how items that Dr. Proctor either could not put a probability on at all, or which had a low probability of occurring, became "known" between the hearings and the writing of Staff's brief, but in any event, Staff's "insurance" proposals are specious. Take asbestos-related claims. Staff is quick to point out (see p. 91 of Staff's brief) that there are 49 claims pending against the Company and claims that this means there is a present, known liability today. Staff fails to point out, however, that the Company has successfully obtained dismissal of more (50) claims than are currently pending, and has settled 22 more. Thus 72 of the 121 claims against the Company already no longer exist. It is thus far from known, certain, or quantified that the Company will in fact bear future liabilities in excess of established reserves for asbestos-related claims, or that 6% of whatever liabilities might be borne will affect rates. See Ex. 59 at pp. 169-160.

Staff next, again, raises the "AG Processing hammer." Staff alleges that AG Processing "threw out" the idea that only specifically defined detriments need to be considered. See Section I.E., *supra*, for our discussion of this issue. Staff is improperly inviting the Commission to speculate about the impact on future rates of six percent of some unquantified number that has not yet been spent and that, if spent, will be spent over the next 25 years for a company with a cost of service in excess of $2 billion, and a current rate base in excess of $4 billion.[81] AG Processing recognizes that the Commission cannot engage in such speculation.

Staff alleges the Company has not been "straightforward" regarding liabilities. Staff's brief at p. 86. Staff thus again misstates the record and cites nothing to back up this false statement. The Asset Transfer Agreement submitted with the Application specifies precisely how liabilities are allocated, as does Exhibit 69 (pages 18-20) and the Company's brief (at pages 26-36).

If there has been a lack of candor (perhaps more accurately, if there has been exaggeration), it has come from Staff. It is not the Company that pulled "preliminary estimates" of future capital costs out of the Company's 10-K report and put a witness on the stand, who admitted she knew little about power plants, to try and convince this Commission that the Company ought to bear future capital investments based upon the unsupported and ridiculous accusation that the Company "consciously" chose not to install pollution control equipment 30 or 40 years ago when it "set up" its plants. It is not the Company who improperly asserts that some greater part of the $2.9 billion of "liabilities" on the Company's balance sheet ought to be transferred,[82] despite the fact that Mr. Gary Weiss testified under oath *without being challenged*

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[81] To which $2.25 billion to $2.75 billion of investment must and will be added by 2006 under this Commission's order in Case No. EC-2002-1.
[82] Staff's brief at p. 89.

on any of these points, that all but two of those liability accounts cannot possibly have any ratemaking impact on Missouri customers.[83]

The "liabilities" issue has been nothing more than a scare tactic on the part of Staff. Large numbers with no basis in fact, and reliance on speculative, hypothetical prognostications have no role in properly deciding this transfer.

VI. NATURAL GAS ISSUES

Except for what the Company believes is an outright falsity discussed below, Staff's brief has nothing new to say on this issue, and the Company rebutted every point Staff raised at pages 41-45 of the Company's initial brief.

The Company does not concede the existence of the following possible detriments, and in fact, as its witnesses have testified, do not believe they exist at all,[84] but in an effort to save even a small amount of paper the Company cuts to the heart of the matter and notes that if (for argument's sake) the Company is completely wrong on these natural gas issues – if Staff is completely right – then:

a. The customers in the Fisk/Lutesville LDC receive no discount on natural gas transportation (if somehow Ameren cannot (or inexplicably fails to) use its substantial leverage to obtain such a discount) in which event these customers might – at worst – pay 50 cents more per month for gas.[85]
b. Similarly, if the Venice and Meramec plants cannot receive quite as good a deal on gas after the transfer as today, Missouri electric customers might – worst case – pay 8.4 cents more *per year* for their electricity.[86]

The Company's initial brief addresses how the record reflects that even this is not going to occur.

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[83] Ex. 8.
[84] Tr. at p. 1090, l. 1 to p. 1091, l. 5; Tr. at p. 1091, l. 20-25; Tr. at p. 1095, l. 5-8. See also Tr. at p. 1748, l. 5-13, wherein Mr. Nelson also testified that it was most likely that the same discount would be obtained for Fisk/Lutesville.
[85] See our initial brief at pp. 44-45 and Tr. at p. 1012, l. 21 to p. 1014, l. 5. Keep in mind that this worst-case scenario where the possibility of 50 cents more per month only occurs if Ameren is able to obtain *no discount at all* for Fisk/Lutesville.
[86] Tr. at p. 1096, l.16 to p. 1097, l. 22.

Not only does Staff say nothing new or convincing, but what Staff asserts is not supported by the record. Staff's adversary brief (but *not* the record) implies some impact on utility service arising from the natural gas related "detriments" Mr. David Sommerer "identified." That implication is false. There is not one word in the record that supports any negative impact on utility service arising from the natural gas issues, and Staff knows it.[87] Why does Staff raise the spectre of "reliability" concerns in its brief when its own witnesses provided no such testimony? Because Staff knows what the Company has been saying all along – this is a Section 393.190.1 case, and the primary focus of such a case is whether a transfer will negatively affect reliability and Staff has no evidence to support any detriment related to reliability.[88]

VII. TRANSMISSION

Like the natural gas issues, there is virtually nothing in Staff's or OPC's brief that the Company has not already addressed at pages 47 to 50 of the Company's initial brief. A few points not addressed warrant a brief discussion.

First, at pages 106 to 107 of Staff's brief, Staff expresses a concern about changes to the JDA that might result from a "renegotiation" of the JDA whereby somehow AmerenCIPS or AEG might seek to extract transmission-related charges from AmerenUE via an amended JDA which, absent the transfer, Staff theorizes they could not extract. Aside from the fact there is no proof that any such change is or ever will be "in the works," which renders this "concern"

[87] Tr. at p. 1009, l. 8 – p. 1010, l. 20; p. 1016, l. 22- p. 1017, l. 2.

[88] One other issue raised in Staff's brief relating to natural gas must be addressed. Staff has called into question Mr. Craig Nelson's integrity, arguing at page 95 of its brief that the Application contained "misleading statements." Mr. Nelson was unaware when he signed the Application or when he filed his direct testimony, that there was one gas contract shared by the Alton, Illinois LDC and the Fisk/Lutesville LDC. Ex. 6 at p. 5, l. 1-16. Ex. 6 at p. 5, l. 1-16. Of course, the transfer does not affect that contract as it will remain an AmerenUE contract and will continue to serve Fisk/Lutesville in accordance with its terms – it is Alton that must bid on the capacity being released by AmerenUE. Ex. 17 at p. 5, l. 6 to p. 7, l. 18. Further, Mr. Nelson did not realize that the two power plants had an operating relationship with the Alton, Illinois LDC. He so stated in his surrebuttal testimony. Ex. 6 at p. 5, l. 1-16. He made no excuses. He simply said he was mistaken, and all necessary corrections are of record in this case.

speculative at best, the only way Staff's concern could become a reality is if *this Commission allows it by approving such a JDA amendment.* AEG and the Company cannot amend the JDA to create such a situation without this Commission's approval because the Company has *bound itself to obtain this Commission's approval to any substantive change to the JDA.*[89] This is just another in a series of concerns about speculative possibilities that have no business in this case.

Second, the Company notes Staff's mischaracterization of a hold harmless condition agreed upon by Ameren Services Company when Ameren acquired Central Illinois Light Company (now d/b/a AmerenCILCO). The City of Springfield, Illinois protested Ameren's CILCO acquisition in part because it had concerns about Ameren having too much market power relating to its control of the Illinois transmission system, market power which the City was concerned could be used to restrict its access to necessary transmission without the incurrence of additional charges.[90] The City's concern was temporary because there were certain identified transmission system upgrades in the works that, when complete, would eliminate the concern, as found by FERC.[91] Thus, to address these market power issues, the Company agreed that until those upgrades were done it would make sure the City remained whole – was held harmless – from higher transmission charges.[92] These were defined, interim measures to address a known, existing, and temporary market power-related issue. They are unlike Staff's request for an open-ended, ill-defined blanket hold harmless from anything and everything that might happen in the future in regards to interstate transmission policy simply as a result of the change in legal title to poles and wires from AmerenUE to AmerenCIPS. Staff admits today there is no existing

[89] Ex. 36 at p. 9 (condition 1.a) of the Stipulation (Attachment 1 to the Commission's Order).
[90] Order Conditionally Authorizing Merger and Granting Waivers and Authorizations, 101 F.E.R.C. 61, 202, 2002 FERC LEXIS 2400.
[91] Id. at ¶¶ 38-46.
[92] Id.

problem, and that the Company has no intention of splitting its control area which might, and the Company emphasizes "might," then create some undefined problem.[93]

OPC also makes unsupported allegations on this topic. OPC (once again, without any support in the record) alleges that transfer of the Illinois transmission assets "could have adverse reliability impacts." OPC's brief at p. 35. The only "support" for this statement is OPC's citation to Mr. Kind's conclusory, unsupported statement in his pre-filed rebuttal testimony which makes a vague reference to "FERC transmission policies." Notably, neither Dr. Proctor nor Mr. Bax alleged any such impact on reliability.[94] Mr. Edward Pfeiffer's testimony (Ex. 13) was straightforward and unequivocal as well. In short, the Company's transmission system before and after the transfer is operated as part of the one, integrated Ameren system within the MISO – changing title to a pole or a wire doesn't change the reliability of the system.[95]

VIII. AFFILIATE TRANSACTIONS RULES

A review of Staff's (and OPC's) briefs now make clear why they are so insistent on applying the affiliate transaction rules to this Section 393.190.1 asset transfer case – they are attempting to manufacture a higher legal standard – a "best interests" standard – in this Section 393.190.1 case because they recognize they cannot win it under the facts and the law that actually and lawfully apply.

[93] See also p. 49 of the Company's initial brief, pointing out that the worst-case scenario in any event if the control area is split and if there are charges and if ...... – might be 80 cents per customer per year, and that even Dr. Proctor admits there is only a 20-25% probability that could happen.
[94] See Exs. 14 and 16.
[95] The Kinmundy plant which AmerenUE seeks to acquire, an acquisition this Commission supports, is and always has been connected to an AmerenCIPS line just as the Venice, Pinckneyville and EE Inc. plants will be after the transfer. Tr. at p. 1188, l. 2 to p. 1189, l. 4. That fact (until this case) was never seen as relevant in considering Kinmundy as a reliable network resource and for good reason, it's not relevant, because the plants will be network resources and available to the Company regardless of the transfer.

Staff's and OPC's dubious (and unlawful) interpretation of the affiliate transaction rules is that the rules, assuming they apply at all, can only be waived if the Company makes an affirmative showing the transfer is "in the best interest" of its customers. They misread the rules.

Under 4 CSR 240-20.015(10)(A), there are two ways to obtain a variance: under Subsection (10)(A)1. *or* under Subsection (10)(A)2.[96] The "best interests" language appears only in Subsection (10)(A)2. Subsection (10)(A)2. applies only when the public utility decides to "engage in an affiliate transaction *not in compliance with the standard set out in sub-section (2)(A) of this rule*" (emphasis added). Subsection (10)(A)2. allows a public utility to engage in an affiliate transaction that does not meet the pricing standards set out in Section (2)(A) if to the "best of its knowledge and belief," compliance with the standards in Section (2)(A) "would not be in the best interests" of its customers. If the utility decides to use Subsection (10)(A)2., i.e., decides to engage in such a transaction without first seeking a waiver, the utility also has to comply with the rather detailed recordkeeping requirements of 4 CSR 240-20.015(10)(A)2.A. and B, which essentially then allow Staff and OPC to "audit" the basis for the Company's belief even though the transaction will already be complete. Presumably this gives Staff and OPC ammunition in the Company's records to seek ratemaking adjustments later if they disagree with the Company's decision to engage in the transaction without complying with the standards set forth in Section 2(A) of the rules.

The Company has not transferred these assets. Rather, the Company has filed a Section 393.190.1 application asking for this Commission's permission to transfer the assets. *If*, and we again assert that is a big "if," the affiliate transaction rules apply to the transfer at all, the Company therefore seeks a variance under Subsection (10)(A)1., which imposes no burden on a utility to show anything having to do with the "best interests of" customers.

[96] The relevant provisions of the rules highlighted in the attached Appendix B.

In any event, the Company has no intention of "selling" its Illinois assets to anyone other than AmerenCIPS. The transfer presents no issue of subsidization of non-utilities, which is the purpose of the rules (see Appendix B). The SEC will not allow the Company to sell these assets to AmerenCIPS at anything other than book value (the approximately $138 million transfer price).[97] The transfer essentially maintains AmerenUE's return on equity at the same level as existed before the transfer and does not increase AmerenCIPS's return on equity.[98] This Commission has a duty to and no doubt will decide if the transfer is detrimental.[99] If the Commission believes the Company needs a variance under Subsection (10)(A).1, the Company hereby requests such a variance.

One final affiliate transaction rule-related point. Staff's brief (p. 119) asserts that the affiliate transaction rules "apply to the JDA". Staff does not explain why its assertion is important in this case. The Company has already agreed to a condition, in Case No. EO-2000-37 (Ex. 36), whereby any substantive amendment to the JDA *must* be approved by this Commission. If the Commission orders the JDA amendment offered in this case, then the Commission obviously would approve of that amendment. If the JDA is amended in a substantive way, the Commission will have to approve that amendment. The affiliate transaction rules therefore have nothing to do with any live issue relating to the JDA in this case.

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[97] See e.g., In re Georgia Power Co., 49 S.E.C. 309 (1984) (In the case of an acquisition from an associate company, "[t]he price is limited to cost.").

[98] Ex. 5 at p. 6, l. 27 to p. 7, l. 3. In fact, it slightly decreases AmerenCIPS's return on equity (Tr. at p. 1034, l. 22 to p. 1035, l. 3), which is a fact OPC conveniently chose to omit when noting that the transfer would increase the earnings of AmerenCIPS. Yes, the transfer will increase the aggregate level of earnings because AmerenCIPS will gain 62,000 electric and 18,000 gas customers. But, AmerenCIPS's return on equity, which is the only relevant financial measure, will decrease slightly and AmerenCIPS's capital structure will remain essentially unchanged.

[99] Staff finds it "remarkable" that this Commission would take on the role of protecting Missouri ratepayers. Staff's brief at p. 115. Frankly, we thought that was one of the Commission's jobs. The Commission's mission statement seems to suggest it is: "ensure that Missourians receive safe and reliable utility services at just, reasonable and affordable rates."

IX. NUCLEAR DECOMMISSIONING

The Company hesitates to consume even one more page with this issue, but Staff's brief raises two new, novel, and incorrect arguments that require a response.

Staff first implies that a "benefit" is being "passed" from Missouri ratepayers to Illinois ratepayers (the implication apparently being that if Illinois ratepayers receive a benefit Missouri ratepayers must somehow be getting a detriment). Illinois ratepayers are losing access to power from Callaway and thus, not surprisingly, will no longer contribute funds to decommission Callaway. Missouri ratepayers are receiving about 6% more of Callaway's power, and thus will be responsible for about 6% more of the decommissioning costs (and will receive about 98% of the funds today held in the Illinois jurisdictional sub-account of the decommissioning fund). Before the transfer, the annual contributions to the Missouri jurisdictional sub-account total $6.2 million and, if the Company's request is granted, will remain $6.2 million. Before the transfer, this Commission determined that this $6.2 million is part of the Company's Missouri cost of service. After the transfer, this $6.2 million will remain a part of the Company's Missouri cost of service. There is no "transfer" of a benefit that creates a detriment for Missouri.

The issue here is simple: do we *increase* the Missouri contribution or not? Resolving the question is simple. Does the Commission agree with the Company, based upon the *only* analysis submitted on this issue which shows there is no need to increase the Missouri contribution, or does the Commission agree with Staff who submitted nothing to support its position? If the Commission agrees with Staff, then it must necessarily find that the additional $272,554 is part of the Company's Missouri cost of service (it has not made such findings) and otherwise must make the findings required by applicable IRS regulations. It's that simple. The Commission can go to the trouble of making those findings now, in the face of a record where the only evidence shows that it is entirely unnecessary to do so, or the entire issue of funding adequacy can be reviewed 15 months from now when the Company's next triennial review is due to occur. Is it not obvious that Staff's opposition to changing the overall funding level by 4.2% (to $6.2 million versus $6.472 million) for the next 15 months or so, based on no evidence supporting its opposition, is an unreasonable position?

Staff's second argument is that the Company's request not to increase its Missouri contribution by $272,000 somehow creates a $22 million "detriment." Staff's arguably misleading mathematics tell only a small part of the story, as the undisputed figures in Mr. Redhage's testimony (See Ex. 2) show.

Without the transfer, Missouri retail customers, based upon the Company's last triennial review case (Case No. EO-2003-0083) are responsible for about 90.92% of the costs to decommission Callaway, or for about $468,546,219 of the estimated total ultimate decommissioning cost of $515,339,000. As of December 31, 2003, the Missouri jurisdictional sub-account had an after-tax liquidation value of $180,433,423. If the transfer did not occur, the value of the Missouri jurisdictional sub-account ($180,433,423) would be about 38.5%[100] of the Missouri retail share of the cost to decommission Callaway ($468,546,219). In other words, today, Missouri retail customers have funded 38.5% of the total amount they will have to ultimately fund.

If the transfer occurs, Missouri will still have funded about 38.5% of the ultimate cost to decommission Callaway because Missouri will receive the funds contributed by Illinois ratepayers which will become part of the Missouri jurisdictional sub-account (i.e. the December 31, 2003 after-tax liquidation value of the Missouri jurisdictional sub-account would increase from $180,433,423 to $194,442, 390), a consideration ignored by Staff. The math works out as

[100] 180,433,423/468,546,219 = .38509.

follows: take the Missouri jurisdictional sub-account balance, post-transfer ($194,442,390) and divide it by the new Missouri share of the total Callaway decommissioning costs (97.92% of $515,339,000, or $504,625,310), and the result is 38.5%. Therefore, the "progress" Missouri retail customers have made toward their ultimate funding obligation is totally unaffected by the transfer.

What Staff has done is taken the future, total cost to decommission Callaway, 61.5% (with or without the transfer) of which is not yet funded (100% - 38.5%), and has suggested that somehow, today, $22 million was shifted to Missouri. That is literally true, but only as far as it goes. Yes, over the next 20 years[101] Missouri retail would fund about 98% of the future decommissioning fund contributions in recognition of the fact that Missouri retail customers would receive about 98% of the power from Callaway, and based upon Staff's math, that additional 6% would total about $22 million based upon current total decommissioning cost estimates. Staff's $22 million "increase" over the next 20 years is probably wrong in any event. As Staff so eagerly points at footnote 16 on page 74 of its brief, the total decommissioning cost estimates for Callaway have changed six times and continue to increase. What Staff fails to point out, however, is that the annual funding level this Commission has found necessary to sufficiently fund Callaway's decommissioning has *never changed.* It is, therefore, a colossal stretch to assert that Missouri retail customers will have to increase their contributions by $22 million or by any sum over the next 20 years, but if they do, so what? The Company has never hidden the fact that Missouri would, after the transfer, fund about 98% versus about 92% of the

[101] Assuming Callaway is decommissioned after 2024, when its current license expires. Tr. at p. 240, l. 7-11.

required contributions, and Staff (until it needed yet another argument for its brief) never took issue with that fact because Missouri retail customers will get 98% of the power![102]

One final reply to Staff's lengthy argument over this $272,554 per year issue is required. Mr. Redhage has been clear. The IRS issues a separate schedule of ruling amount for each of AmerenUE's jurisdictions, including one for the Illinois jurisdictional sub-account and one for the Missouri jurisdictional sub-account.[103] This is based upon the ICC's separate determination that the $272,554 is a part of the Company's Illinois cost of service and this Commission's separate determination that the $6.2 million is part of the Company's Missouri cost of service. The applicable IRS regulations also require this Commission to determine that the $6.472 million contribution for Missouri (reflecting the $272,554 increase) is a part of the Company's Missouri cost of service if this Commission determines that the Company must make this contribution.[104] The applicable IRS regulations also require this Commission to disclose the financial parameters and other assumptions on which it basis that determination.[105] The Company will have to take an order from this Commission to the IRS to receive the required ruling, meaning this Commission will have to make those findings – now. What is Staff's rebuttal? They want this Commission to rely on the obvious guess Mr. Greg Meyer was making on the fly when asked about this issue by Commissioner Murray. Mr. Meyer opined that in "his mind" no Commission cost of service finding and no IRS filing would be required, and he "guessed" that Staff's opinion on this was based on testimony in Case No. EM-96-149.[106] Mr. Meyer even admitted that he did not know whether each jurisdiction (Illinois and Missouri) had to substantiate what

[102] Because the least cost analysis assumes the $272,554 will be contributed, this additional 6% also would not change the overall level of benefits from the transfer.
[103] Tr. at p. 229, l. 11-18; Ex. 2 at p. 11, l. 9 to p. 12, l. 28; Treas. Reg. 26 CFR 1.468A-3(f).
[104] Treas. Reg. 26 CFR 1.468A-3(g).
[105] Id.
[106] Tr. at p. 348, l. 3 to 349, l. 19.

each jurisdiction had found. Yes, there is one decommissioning fund, but as Mr. Redhage has testified, there are different sub-accounts – a Missouri retail sub-account, and Illinois retail sub-account, plus a wholesale sub-account. This Commission must make findings to support funding the Missouri sub-account and the ICC must make findings to support funding the Illinois sub-account, and the Company cannot fund the Missouri sub-account at a higher level than this Commission has previously found in the Missouri retail cost of service without further findings from this Commission and further IRS approval.

X. STAFF'S IMPROPER BOOKS AND RECORDS "CONDITION"

The Company earlier alleged that this case is a prime example of a common, and improper, tactic utilized by Staff and Public Counsel – the use of various Commission proceedings to extract conditions unrelated to the proceeding at issue from utility companies. Staff's "access to books and records" condition discussed at pages 121-123 of its brief is just that kind of improper condition. Staff has not made – in fact has not even attempted to make – any showing of how this Commission has the authority in a Section 393.190.1 asset transfer case to enlarge existing law, both statutory (Section 393.140(11), RSMo.) and the affiliate transaction rules, with regard to access to the books and records of a public utility company or of its affiliates. If, in an agreed-to settlement, a public utility, like KCPL apparently did in its EM-2001-464 case, is willing to voluntarily agree to give the Commission certain information otherwise not obtainable, then so be it. But that does not allow the Commission to impose unlawful conditions having nothing to do with the proposed asset transfer just because Staff wants them.

XI. OPC'S QUEST FOR AN RFP

OPC contends the Company ought to engage in a request for proposal (RFP) process in determining how to best meet its long-term needs for energy and capacity. OPC's position is at odds with the Commission's resource planning rules (4 CSR 22.060 which require a planning horizon of at least 20 years), is contrary to Staff's position, in particular that of Dr. Proctor, and is at odds with the directive of this Commission, reflected in its order approving the Stipulation and Agreement in Case No. EC-2002-1, which calls for the Company to invest in Company-owned generation.

Dr. Proctor's testimony on this is clear:[107]

> **Q. What is Mr. Kind's position on the need for AmerenUE to issue an RFP with respect to the Metro East Transfer?**
>
> A. Mr. Kind's position is that an RFP is required in order to determine the minimum cost alternative to the Metro East Transfer.
>
> **Q. Do you agree with that [sic] an RFP is needed to determine the minimum cost alternative to the Metro East transfer?**
>
> A. No, I do not agree with that position. The Metro East transfer is a long-term addition of capacity and lower cost energy to meet the needs of AmerenUE's remaining load. In contrast, an RFP would primarily be used by AmerenUE to solicit capacity to meet AmerenUE's short-term needs for reserves. By this, I mean that if AmerenUE is planning to add capacity and there is evidence that capacity can be purchased for a short period of time at a cost that is below the cost of adding new capacity, then an RFP would be issued to determine whether or not it is less costly to delay the addition of the new capacity and in the interim enter into a short-term contract. This strategy is particularly relevant for AmerenUE because of its existing capacity mix. Moreover, because of its abundance of base-load capacity, it is unlikely that AmerenUE will be able to purchase energy from the market at a lower cost than it would incur by generating that energy from its existing plants.
>
> **Q. Would it be possible for AmerenUE to issue an RFP for long-term energy and capacity?**
>
> A. Anything is possible, but the longer the term of the contract, the less likely that any existing generation will be able to meet the terms of the contract. Thus, long- term contracts usually involve building a new plant. Even if an existing Independent Power Producer has existing capacity and is willing to enter into a long-term contract, the price of such a contract will likely reflect the cost of a new plant. At that point, it makes more sense for AmerenUE to build the plant itself than to incur the risk of higher costs when the contract expires.
>
> **Q. What additional information would AmerenUE have gained had it issued an RFP?**

[107] Ex. 15 at p. 5, l. 6 to p. 6, l. 18.

A. At most, AmerenUE would have been able to determine if it could have delayed the addition of the combustion turbines that it would otherwise have had to construct absent the Metro East transfer. In an apples-to-apples comparison of the two alternatives, the RFP could also have resulted in purchases that would delay the Metro East transfer. Thus, if an RFP is an issue, the only issue it raises is the timing of AmerenUE's request for the Metro East transfer. With the rate moratorium in place, I see very little benefit to AmerenUE's Missouri retail ratepayers from taking this approach.

CONCLUSION

For the reasons, and based on the *record*, discussed in our initial brief and in this Reply Brief, we respectfully request that the Commission approve the Company's request to transfer these Illinois assets, without conditions,[108] and that the Commission do so promptly.

Dated: June 9, 2004.

Respectfully Submitted,

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[108] We do not believe it is necessary, but will accept the JDA amendment condition we have offered, will proceed with the transfer regardless of the Commission's ruling on the decommissioning fund issue, and are not asking for ratemaking treatment (save relating to decommissioning).

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing document was served on the following parties of record by United States mail, postage prepaid, this 9th day of June, 2004, at the addresses set forth below:

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APPENDIX A
Record Evidence Demonstrating Ratemaking Tools That Remain Available to the Commission

Tr. at p. 344, l. 5 – 24 (Discussing Staff's proposed condition, that the Commission make clear that approval of the transfer does not "give anything away for ratemaking purposes or concede anything for ratemaking purposes" – a condition to which the Company, as we have stated repeatedly, has no objection);

Tr. at p. 620, l. 8 – p. 621, l. 5 (Where, in response to Chair Gaw's questions, Staff witness Campbell noted that "in the latter case [a later rate case – *not* this asset transfer case], you would probably have a more secure hold on the dollar figures . . ." and "may in a later [rate] case you'd have a better idea of what that would be.");

Tr. at p. 645, l. 25 – p. 646, l. 6 ("Q. [by Commissioner Murray] Would it be fair to say that a future Commission in a rate case would have the authority to hold ratepayers harmless from the decisions that Ameren may be making in regard to its SO2 emissions policies and sales of credits? A. [by Mr. Kind – reluctantly] If the – I guess under the current system of regulation, probably so." Does Mr. Kind seriously contend that this Commission ought to deny permission for the proposed transfer on the premise that (a) future Commissioners will fail to exercise their sworn duty to ensure just and reasonable rates or (b) that the Legislature might change the law to allow utilities to run roughshod over ratepayers thus requiring the current Commission to trample on the utility's rights today by denying permission for asset transfers on the basis of speculative possibilities of future cost impacts?);

Tr. at p. 919, l. 1 to p. 920, l. 12; p. 939, l. 6 - 21 (Demonstrating that another proposed "detriment" for which Staff seeks conditions (the JDA) can be, and will be, if Staff remains dissatisfied, be addressed in a future rate case, in fact has been addressed in past rate cases, and that parties are free, in future rate cases, to file testimony and propose adjustments that this Commission is fully capable of considering and accepting or rejecting in whole or on part in such rate cases);

Tr. at p. 1004, l. 24 to p. 1005, l. 6; p. 1008, l. 22 to p. 1009, l. 1 ("Q. And it's also my understanding that the Staff can and has proposed disallowance in these costs? A. That is correct. Q. Okay. And there would be nothing to prevent you from proposing disallowances in future PGA proceedings involving the Fisk-Lutesville system after October 2006, would there? A. No. I don't believe there would be." "Q. Okay. Because you're not saying, are you, that the Commission would not have the power to disallow costs in a rate case. A. To the extent that there was not pre-approval, I think they have full authority to disallow costs." As noted above, the Staff has asked that the Commission make clear, and the Company has agreed, that any Commission order approving the transfer will not constitute "pre-approval" or ratemaking approval.);

Tr. at p. 1064, l. 9 – 14 (Where another Staff witness concedes that costs (such as the liabilities Staff spends so much time talking about) might or might not affect rates in the future, and that today we do not know whether such costs will or will not affect rates);

Tr. at p. 1255, l. 17 – 25 (Where Dr. Proctor confirms that if future transmission charges somehow arose from a future split of Ameren's control area this Commission will determine the rate impact and that charges could be addressed in a future rate case).

Title 4—DEPARTMENT OF ECONOMIC DEVELOPMENT
Division 240—Public Service Commission
Chapter 20—Electric Utilities

4 CSR 240-20.010 Rate Schedules
(Rescinded April 30, 2003)

AUTHORITY: section 393.140, RSMo 1986. Original rule filed Dec. 19, 1975, effective Dec. 29, 1975. Amended: Filed May 16, 1977, effective Dec. 11, 1977. Rescinded: Filed Aug. 16, 2002, effective April 30, 2003.

4 CSR 240-20.015 Affiliate Transactions

PURPOSE: This rule is intended to prevent regulated utilities from subsidizing their nonregulated operations. In order to accomplish this objective, the rule sets forth financial standards, evidentiary standards and record-keeping requirements applicable to any Missouri Public Service Commission (commission) regulated electrical corporation whenever such corporation participates in transactions with any affiliated entity (except with regard to HVAC services as defined in section 386.754, RSMo Supp. 1998, by the General Assembly of Missouri). The rule and its effective enforcement will provide the public the assurance that their rates are not adversely impacted by the utilities' nonregulated activities.

(1) Definitions.

(A) Affiliated entity means any person, including an individual, corporation, service company, corporate subsidiary, firm, partnership, incorporated or unincorporated association, political subdivision including a public utility district, city, town, county, or a combination of political subdivisions, which directly or indirectly, through one (1) or more intermediaries, controls, is controlled by, or is under common control with the regulated electrical corporation.

(B) Affiliate transaction means any transaction for the provision, purchase or sale of any information, asset, product or service, or portion of any product or service, between a regulated electrical corporation and an affiliated entity, and shall include all transactions carried out between any unregulated business operation of a regulated electrical corporation and the regulated business operations of a electrical corporation. An affiliate transaction for the purposes of this rule excludes heating, ventilating and air conditioning (HVAC) services as defined in section 386.754 by the General Assembly of Missouri.

(C) Control (including the terms "controlling," "controlled by," and "common control") means the possession, directly or indirectly, of the power to direct, or to cause the direction of the management or policies of an entity, whether such power is exercised through one (1) or more intermediary entities, or alone, or in conjunction with, or pursuant to an agreement with, one or more other entities, whether such power is exercised through a majority or minority ownership or voting of securities, common directors, officers or stockholders, voting trusts, holding trusts, affiliated entities, contract or any other direct or indirect means. The commission shall presume that the beneficial ownership of ten percent (10%) or more of voting securities or partnership interest of an entity constitutes control for purposes of this rule. This provision, however, shall not be construed to prohibit a regulated electrical corporation from rebutting the presumption that its ownership interest in an entity confers control.

(D) Corporate support means joint corporate oversight, governance, support systems and personnel, involving payroll, shareholder services, financial reporting, human resources, employee records, pension management, legal services, and research and development activities.

(E) Derivatives means a financial instrument, traded on or off an exchange, the price of which is directly dependent upon (i.e., "derived from") the value of one or more underlying securities, equity indices, debt instruments, commodities, other derivative instruments, or any agreed-upon pricing index or arrangement (e.g., the movement over time of the Consumer Price Index or freight rates). Derivatives involve the trading of rights or obligations based on the underlying product, but do not directly transfer property. They are used to hedge risk or to exchange a floating rate of return for a fixed rate of return.

(F) Fully distributed cost (FDC) means a methodology that examines all costs of an enterprise in relation to all the goods and services that are produced. FDC requires recognition of all costs incurred directly or indirectly used to produce a good or service. Costs are assigned either through a direct or allocated approach. Costs that cannot be directly assigned or indirectly allocated (e.g., general and administrative) must also be included in the FDC calculation through a general allocation.

(G) Information means any data obtained by a regulated electrical corporation that is not obtainable by nonaffiliated entities or can only be obtained at a competitively prohibitive cost in either time or resources.

(H) Preferential service means information or treatment or actions by the regulated electrical corporation which places the affiliated entity at an unfair advantage over its competitors.

(I) Regulated electrical corporation means every electrical corporation as defined in section 386.020, RSMo, subject to commission regulation pursuant to Chapter 393, RSMo.

(J) Unfair advantage means an advantage that cannot be obtained by nonaffiliated entities or can only be obtained at a competitively prohibitive cost in either time or resources.

(K) Variance means an exemption granted by the commission from any applicable standard required pursuant to this rule.

(2) Standards.

(A) A regulated electrical corporation shall not provide a financial advantage to an affiliated entity. For the purposes of this rule, a regulated electrical corporation shall be deemed to provide a financial advantage to an affiliated entity if—

1. It compensates an affiliated entity for goods or services above the lesser of—
   A. The fair market price; or
   B. The fully distributed cost to the regulated electrical corporation to provide the goods or services for itself; or
2. It transfers information, assets, goods or services of any kind to an affiliated entity below the greater of—
   A. The fair market price; or
   B. The fully distributed cost to the regulated electrical corporation.

(B) Except as necessary to provide corporate support functions, the regulated electrical corporation shall conduct its business in such a way as not to provide any preferential service, information or treatment to an affiliated entity over another party at any time.

(C) Specific customer information shall be made available to affiliated or unaffiliated entities only upon consent of the customer or as otherwise provided by law or commission rules or orders. General or aggregated customer information shall be made available to affiliated or unaffiliated entities upon similar terms and conditions. The regulated electrical corporation may set reasonable charges for costs incurred in producing customer information. Customer information includes information provided to the regulated utility by affiliated or unaffiliated entities.

(D) The regulated electrical corporation shall not participate in any affiliated transactions which are not in compliance with this rule, except as otherwise provided in section (10) of this rule.

(E) If a customer requests information from the regulated electrical corporation about goods or services provided by an affiliated entity, the regulated electrical corporation may provide information about its affiliate but must inform the customer that regulated services are not tied to the use of an affiliate provider and that other service providers may be available. The regulated electrical corporation may provide reference to other service providers or to commercial listings, but is not required to do so. The regulated electrical corporation shall include in its annual Cost Allocation Manual (CAM), the criteria, guidelines and procedures it will follow to be in compliance with this rule.

(F) Marketing materials, information or advertisements by an affiliate entity that share an exact or similar name, logo or trademark of the regulated utility shall clearly display or announce that the affiliate entity is not regulated by the Missouri Public Service Commission.

(3) Evidentiary Standards for Affiliate Transactions.

(A) When a regulated electrical corporation purchases information, assets, goods or services from an affiliated entity, the regulated electrical corporation shall either obtain competitive bids for such information, assets, goods or services or demonstrate why competitive bids were neither necessary nor appropriate.

(B) In transactions that involve either the purchase or receipt of information, assets, goods or services by a regulated electrical corporation from an affiliated entity, the regulated electrical corporation shall document both the fair market price of such information, assets, goods and services and the FDC to the regulated electrical corporation to produce the information, assets, goods or services for itself.

(C) In transactions that involve the provision of information, assets, goods or services to affiliated entities, the regulated electrical corporation must demonstrate that it—

1. Considered all costs incurred to complete the transaction;

2. Calculated the costs at times relevant to the transaction;

3. Allocated all joint and common costs appropriately; and

4. Adequately determined the fair market price of the information, assets, goods or services.

(D) In transactions involving the purchase of goods or services by the regulated electrical corporation from an affiliated entity, the regulated electrical corporation will use a commission-approved CAM which sets forth cost allocation, market valuation and internal cost methods. This CAM can use benchmarking practices that can constitute compliance with the market value requirements of this section if approved by the commission.

(4) Record Keeping Requirements.

(A) A regulated electrical corporation shall maintain books, accounts and records separate from those of its affiliates.

(B) Each regulated electrical corporation shall maintain the following information in a mutually agreed-to electronic format (i.e., agreement between the staff, Office of the Public Counsel and the regulated electrical corporation) regarding affiliate transactions on a calendar year basis and shall provide such information to the commission staff and the Office of the Public Counsel on, or before, March 15 of the succeeding year:

1. A full and complete list of all affiliated entities as defined by this rule;

2. A full and complete list of all goods and services provided to or received from affiliated entities;

3. A full and complete list of all contracts entered with affiliated entities;

4. A full and complete list of all affiliate transactions undertaken with affiliated entities without a written contract together with a brief explanation of why there was no contract;

5. The amount of all affiliate transactions by affiliated entity and account charged; and

6. The basis used (e.g., fair market price, FDC, etc.) to record each type of affiliate transaction.

(C) In addition, each regulated electrical corporation shall maintain the following information regarding affiliate transactions on a calendar year basis:

1. Records identifying the basis used (e.g., fair market price, FDC, etc.) to record all affiliate transactions; and

2. Books of accounts and supporting records in sufficient detail to permit verification of compliance with this rule.

(5) Records of Affiliated Entities.

(A) Each regulated electrical corporation shall ensure that its parent and any other affiliated entities maintain books and records that include, at a minimum, the following information regarding affiliate transactions:

1. Documentation of the costs associated with affiliate transactions that are incurred by the parent or affiliated entity and charged to the regulated electrical corporation;

2. Documentation of the methods used to allocate and/or share costs between affiliated entities including other jurisdictions and/or corporate divisions;

3. Description of costs that are not subject to allocation to affiliate transactions and documentation supporting the nonassignment of these costs to affiliate transactions;

4. Descriptions of the types of services that corporate divisions and/or other centralized functions provided to any affiliated entity or division accessing the regulated electrical corporation's contracted services or facilities;

5. Names and job descriptions of the employees from the regulated electrical corporation that transferred to a nonregulated affiliated entity;

6. Evaluations of the effect on the reliability of services provided by the regulated electrical corporation resulting from the access to regulated contracts and/or facilities by affiliated entities;

7. Policies regarding the availability of customer information and the access to services available to nonregulated affiliated entities desiring use of the regulated electrical corporation's contracts and facilities; and

8. Descriptions of and supporting documentation related to any use of derivatives that may be related to the regulated electrical corporation's operation even though obtained by the parent or affiliated entity.

(6) Access to Records of Affiliated Entities.

(A) To the extent permitted by applicable law and pursuant to established commission discovery procedures, a regulated electrical corporation shall make available the books and records of its parent and any other affiliated entities when required in the application of this rule.

(B) The commission shall have the authority to—

1. Review, inspect and audit books, accounts and other records kept by a regulated electrical corporation or affiliated entity for the sole purpose of ensuring compliance with this rule and making findings available to the commission; and

2. Investigate the operations of a regulated electrical corporation or affiliated entity and their relationship to each other for the sole purpose of ensuring compliance with this rule.

(C) This rule does not modify existing legal standards regarding which party has the burden of proof in commission proceedings.

(7) Record Retention.

(A) Records required under this rule shall be maintained by each regulated electrical corporation for a period of not less than six (6) years.

(8) Enforcement.

(A) When enforcing these standards, or any order of the commission regarding these standards, the commission may apply any remedy available to the commission.

(9) The regulated electrical corporation shall train and advise its personnel as to the requirements and provisions of this rule as appropriate to ensure compliance.

(10) Variances.

(A) A variance from the standards in this rule may be obtained by compliance with paragraphs (10)(A)1. or (10)(A)2. The granting of a variance to one regulated electrical corporation does not constitute a waiver respecting or otherwise affect the required compliance of any other regulated electrical corporation to comply with the standards. The scope of a variance will be determined based on the facts and circumstances found in support of the application.

1. The regulated electrical corporation shall request a variance upon written application in accordance with commission procedures set out in 4 CSR 240-2.060(11); or

2. A regulated electrical corporation may engage in an affiliate transaction not in compliance with the standards set out in subsection (2)(A) of this rule, when to its best knowledge and belief, compliance with the standards would not be in the best interests of its regulated customers and it complies with the procedures required by subparagraphs (10)(A)2.A. and (10)(A)2.B. of this rule—

A. All reports and record retention requirements for each affiliate transaction must be complied with; and

B. Notice of the noncomplying affiliate transaction shall be filed with the secretary of the commission and the Office of the Public Counsel within ten (10) days of the occurrence of the non-complying affiliate transaction. The notice shall provide a detailed explanation of why the affiliate transaction should be exempted from the requirements of subsection (2)(A), and shall provide a detailed explanation of how the affiliate transaction was in the best interests of the regulated customers. Within thirty (30) days of the notice of the noncomplying affiliate transaction, any party shall have the right to request a hearing regarding the noncomplying affiliate transaction. The commission may grant or deny the request for hearing at that time. If the commission denies a request for hearing, the denial shall not in any way prejudice a party's ability to challenge the affiliate transaction at the time of the annual CAM filing. At the time of the filing of the regulated electrical corporation's annual CAM filing the regulated electrical corporation shall provide to the secretary of the commission a listing of all non-complying affiliate transactions which occurred between the period of the last filing and the current filing. Any affiliate transaction submitted pursuant to this section shall remain interim, subject to disallowance, pending final commission determination on whether the noncomplying affiliate transaction resulted in the best interests of the regulated customers.

(11) Nothing contained in this rule and no action by the commission under this rule shall be construed to approve or exempt any activity or arrangement that would violate the antitrust laws of the state of Missouri or of the United States or to limit the rights of any person or entity under those laws.

AUTHORITY: sections 386.250, RSMo Supp. 1998, and 393.140, RSMo 1994. Original rule filed April 26, 1999, effective Feb. 29, 2000.*

**Original authority: 386.250, RSMo 1963, amended 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996 and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-20.017 HVAC Services Affiliate Transactions

PURPOSE: This rule prescribes the requirements for HVAC services affiliated entities and regulated electric corporations when such electric corporations participate in affiliated transactions with an HVAC affiliated entity as set forth in sections 386.754, 386.756, 386.760, 386.762 and 386.764, RSMo by the General Assembly of the State of Missouri.

(1) Definitions.

(A) Affiliated entity means any entity not regulated by the Public Service Commission which is owned, controlled by or under common control with a utility and is engaged in HVAC services.

(B) Control (including the terms "controlling," "controlled by," and "common control") means the possession, directly or indirectly, of the power to direct, or to cause the direction of the management or policies of an entity, whether such power is exercised through (1) one or more intermediary entities, or alone, or in conjunction with, or pursuant to an agreement with, one (1) or more other entities, whether such power is exercised through a majority or minority ownership or voting of securities, common directors, officers or stockholders, voting trusts, holding trusts, affiliated entities, contract or any other direct or indirect means. The commission shall presume that the beneficial ownership of more than ten percent (10%) of voting securities or partnership interest of an entity confers control for purposes of this rule. This provision, however, shall not be construed to prohibit a regulated electric corporation from rebutting the presumption that its ownership interest in an entity confers control.

(C) Fully distributed cost means a methodology that examines all costs of an enterprise in relation to all the goods and services that are produced. Fully distributed cost requires recognition of all costs incurred directly or indirectly used to produce a good or service. Costs are assigned either through a direct or allocated approach. Costs that cannot be directly assigned or indirectly allocated (e.g. general and administrative) must also be included in the fully distributed cost calculation through a general allocation.

(D) HVAC services means the warranty, sale, lease, rental, installation, construction, modernization, retrofit, maintenance or repair of heating, ventilating and air conditioning (HVAC) equipment.

(E) Regulated electric corporation means an electrical corporation as defined in section 386.020, RSMo, subject to commission regulation pursuant to Chapter 393, RSMo.

(F) Utility contractor means a person, including an individual, corporation, firm, incorporated or unincorporated association or other business or legal entity, that contracts, whether in writing or not in writing, with a regulated electric corporation to engage in or assist any entity in engaging in HVAC services, but does not include employees of a regulated electric corporation.

(2) A regulated electric corporation may not engage in HVAC services, except by an affiliated entity, or as provided in section (8) or (9) of this rule.

(3) No affiliated entity or utility contractor may use any vehicles, service tools, instruments, employees, or any other regulated electric corporation assets, the cost of which are recoverable in the regulated rates for regulated electric corporation service, to engage in HVAC services unless the regulated electric corporation is compensated for the use of such assets at the fully distributed cost to the regulated electric corporation.