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Witness: Michael L. Moehn
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2007-0002

SURREBUTTAL TESTIMONY

OF

MICHAEL L. MOEHN

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

St. Louis, Missouri
February, 2007

AmerenUE Exhibit No. 37-NP
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OF

MICHAEL L. MOEHN

CASE NO. ER-2007-0002

Q. Please state your name and business address.

A. My name is Michael L. Moehn. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63166-6149.

Q. Are you the same Michael L. Moehn that filed Direct and Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your Surrebuttal Testimony?

A. The purpose of my testimony is to (a) address the testimonies of Michael Brosch, Ryan Kind, and Robert Schallenberg related to Electric Energy, Inc. (EEInc.); (b) address the testimony of Missouri Department of Natural Resources (DNR) witness Brenda Wilbers and the testimony of Missouri Public Service Commission Staff witness Lena Mantle, as they relate to demand side management (DSM) programs; and (c) address the facts relating to the early exercise by Dynegy of emission allowance options sold to Dynegy in 2001, which was addressed in Office of the Public Counsel (OPC) witness Ryan P. Kind's Rebuttal Testimony.

I. EEInc. Issues.

Q. Please summarize your testimony relating to EEInc.

A. AmerenUE's investment in EEInc. was made by its shareholders as part of a unique national defense initiative, as Mr. Svanda has explained. Essentially, a consortium of private utilities got together in the early 1950s to build a new plant in Joppa, Illinois, to generate electricity for the Federal Government's new uranium enrichment facility in Paducah, Kentucky. Because EEInc. stock was purchased with shareholder funds, that asset never became part of AmerenUE's rate base. It was, as the common expression puts it, a "below-the-line" investment. The expense of purchasing power from EEInc. was included in AmerenUE's cost of service as purchased power costs, the same as with any other power agreements. To be sure, an enterprise like EEInc. had never been attempted before, and it was risky, but AmerenUE put its shareholders' money, not its ratepayers', at risk.

Power from the Joppa Plant was sold, as was common up to the introduction of transparent, wholesale markets in the early- to mid-2000s, in cost-based, long-term contracts. Consistent with the whole point of the project, the Government purchased the lion's share of the power from the Joppa Plant over the years. The sponsoring utilities were able to purchase power not taken by the Government in proportion to the percentage of EEInc. stock they owned. While AmerenUE's shareholders own 40% of EEInc.'s stock, AmerenUE's ratepayers purchased only about 16% of the power from the Joppa Plant from 1954 to 2005.

By the end of EEInc.'s Power Supply Agreement (PSA) with AmerenUE in December, 2005, a true regional market for wholesale power, regulated exclusively by the Federal Energy Regulatory Commission (FERC), had been established, and EEInc. secured from the FERC the specific authority needed to allow it to sell its power at market prices. In the Midwest, that transparent wholesale market did not officially emerge until April of 2005, when the Midwest Independent Transmission System Operator, Inc. (MISO) commenced its "Day Two Market." The Board of Directors of EEInc. voted that it was in the obvious best interest of EEInc. to sell its power going forward at a market price when the PSA expired, not on the cost basis it had done before.

The risks associated with the EEInc. investment did not on the whole materialize. Power from the Joppa Plant turned out to be relatively low-cost; power purchases made by the Federal Government provided revenues that covered most of the major costs of the Joppa Plant and provided a return on the shareholders' investment; and the PSA turned out to be a very good deal for AmerenUE's ratepayers because AmerenUE was able to buy a share of the power not taken by the Government at a relatively low-cost rate and use that power as part of its purchased power portfolio to provide service to ratepayers.

Given that market prices now are significantly higher than the Joppa Plant's cost of producing power, the Staff, the Office of Public Counsel, and some of the intervenors understandably wish that Joppa Plant's power could somehow still be purchased at below-market, cost-based prices. In this proceeding, in an attempt to achieve that end and turn back the clock, they blame AmerenUE for not getting EEInc. to sell its power at below-market prices. They seek to penalize AmerenUE for what they consider its "imprudence" by imputing the remarkable sum of $80 million to AmerenUE's revenues in the determination of its cost of service, purportedly due to AmerenUE's failure to continue to purchase Joppa power at a below-market price. Now that AmerenUE's shareholders have successfully borne the risks of the EEInc. investment, these parties want the good deal to continue, and want to punish AmerenUE for not doing something it cannot do – compel a separate corporation to take a step against its economic interests and against its legal rights.

Most strikingly, the parties really do not dispute the material facts on the EEInc. issue. As the Rebuttal Testimonies and Mr. Schallenberg's deposition make clear, these parties either mischaracterize the facts, or offer legal conclusions, in such a manner as to support their claim that AmerenUE has some way of compelling EEInc. to sell its power at a below-market price. None of the witnesses of the other parties are lawyers or are in any other way competent to offer legal opinions on this issue. I am not competent to offer legal opinions either, and with respect to those legal questions, I refer the Commission to the testimonies offered by Prof. Robert Downs, a law professor who has spent a long and distinguished career teaching and studying the very corporate governance issues at the core of the EEInc. matter.

Factually, the EEInc. contract, while having some distinctive features reflecting the new national defense initiative of which it was part, is a typical, long-term, firm power contract. The price set was determined by a cost-based formula common at the time, before FERC Order 888 and the development of a transparent wholesale power market. That price included – again, as was common – both an energy charge (covering variable costs, such as fuel costs) and a capacity or demand charge (covering fixed costs, including a return on and return of investment).

The *sponsoring utilities* (but not ratepayers) did commit to purchase EEInc.'s power if the Government did not do so, and did commit to paying a capacity charge even if the plant did not produce power. But the risk of these events materializing was borne by the sponsoring utilities' shareholders (including AmerenUE's shareholders). AmerenUE has consistently treated the investment in EEInc. as below-the-line, and not one shred of evidence remotely suggests that AmerenUE would have changed that position to attempt to recover in its cost of service expenses that did not relate to power actually received and used by its ratepayers. And even if one speculates that AmerenUE would take such a step, it is certainly reasonable to expect that other parties would protest, and the Commission would not allow such an expense to be included in AmerenUE's cost of service.

In the end, the PSA was a good deal for AmerenUE and its ratepayers. AmerenUE has never relaxed its efforts to provide electricity for its customers at the cheapest price possible consistent with reliability. However, in today's wholesale market, the power from the Joppa Plant is no longer available at the below-market price of the now-expired PSA, and AmerenUE cannot change that fact. AmerenUE was successful in securing low cost power from EEInc. under the rules of the "old world" that had no transparent market for wholesale power, and in which power could be sold only at a cost-based price. AmerenUE intends to vigorously pursue low cost power for its customers under the rules of the new market-based world in which it must now operate.

However, AmerenUE does not set the rules, and it cannot turn back the clock as the other parties wish. It is simply unfair and unreasonable to punish AmerenUE for EEInc.'s decision to legitimately exercise its rights to sell its power for at its fair market value.

A. <u>The Undisputed Facts</u>.

Q. You have mentioned that the material facts relating to EEInc. are really not disputed by the parties. What are those facts?

A. I believe the following key facts concerning the EEInc. issue are not disputed:

- EEInc. was incorporated in 1950 when five independent Midwest utilities (the "Sponsoring Companies") came together to form a new generating company called Electric Energy, Inc., whose primary purpose was to provide electric power for a defense-related uranium enrichment facility being constructed by the Federal Government at Paducah, Kentucky.

- EEInc.'s plant at Joppa, Illinois, was initially financed with a capital structure of approximately 96% debt and 4% equity, for the purpose of minimizing income taxes and income. The SEC approved the unconventional capital structure on the strength of the power contracts between EEInc. and the Government and the Sponsors, along with the national defense purpose of the enterprise.

- The equity investment in EEInc. by the five utilities was made with shareholder funds and has always been treated as a below-the-line investment for ratemaking purposes.

- AmerenUE owns 40% of the capital stock of EEInc. The Commission granted Union Electric the authority to acquire this stock in Case No. 12,064 (1950) and Case No. 12,463 (1952).
- EEInc.'s principal asset is the coal-fired Joppa generating station. EEInc. also owns four subsidiaries: Joppa & Eastern Railroad Company (short line railroad); Massac Enterprises, LLC (enterprise zone retailer); Met-South, Inc. (fly ash seller); and Midwest Electric Power, Inc. (MEPI) (combustion turbine generating facility).
- Dividends paid from the earnings of EEInc. flow to the shareholders of the Sponsoring Companies, as do any gains and/or losses associated with any investments made by EEInc.
- The Government and the Sponsoring Companies were required, through separate purchase power agreements, to buy 100% of EEInc.'s power. As was common, both capacity and energy charges were included in the calculation of the price in order to recover all the costs of producing that power. Included in the fixed costs covered by these charges was a return on equity (ROE).
- Under the terms of the agreement with the Sponsoring Companies, the Sponsoring Companies had an obligation to buy the power from EEInc. that was not purchased by the Government.
- The initial Power Contract, No. AT-(40-1)-1312, was signed in 1951 and has been modified and revised a number of times over the past fifty years, with the most significant revision occurring in 1987 with Modification No. 12, which was entered into September 2, 1987, by EEInc. and the Department of Energy (DOE), and which expired by its express terms on December 31, 2005.
- EEInc. signed a separate PSA with the Sponsoring Companies that tracked Modification 12. It also expired by its express terms on December 31, 2005.
- The cost of the power purchased from EEInc. has been included in AmerenUE's cost-of-service as a purchased power cost. No one has ever claimed that these expenses were imprudent and the Commission has never disallowed them. Nor has anyone ever claimed that the terms of the purchased power contracts were imprudent and the Commission has never made any such finding.
- Over the life of the various power contracts from 1954-2005, the Government and the other Sponsoring Companies paid for approximately 84% of EEInc.'s total costs of producing power at the Joppa Plant. AmerenUE paid for approximately 16% of EEInc.'s total Joppa Plant costs over this same period.
- The MISO Day Two Market began on April 1, 2005.

- EEInc. received FERC approval in December 2005 to sell power at market-based prices. The Commission and the Missouri Industrial Energy Consumers filed notices of intervention, but did not file comments or protests to the application. The OPC filed a motion to intervene and protest. All of OPC's arguments were rejected by FERC.

B. "Prudence."

Q. What is the main justification for the other parties' proposed adjustments to AmerenUE's cost of service based on EEInc.'s decision to sell Joppa power at a market price?

A. Mr. Schallenberg, for the Staff, contends that AmerenUE has behaved imprudently by not compelling EEInc. to sell its power at a below-market price. [Schallenberg Rebuttal 16:21-17:4.] Indeed, he has testified that "AmerenUE directors" on the EEInc. Board were supposed to "represent" AmerenUE's interests and that AmerenUE should have directed those directors to vote to have EEInc. continue to sell power to AmerenUE at below-market prices. [Schallenberg Deposition 26:13-20.] Similarly, Mr. Brosch, for the State, claims that the failure of AmerenUE's management to take such action created an "inequitable outcome" that is corrected by his adjustment. [Brosch Rebuttal 11:17-22.] Mr. Kind, for Office of Public Counsel, argues that if AmerenUE had the public interest and state resource planning in mind it would have voted to extend the below-market contract, and then tries to offer a legal opinion he is not qualified to offer that such an action would not be a violation of the directors' fiduciary duty to EEInc.'s shareholders. [Kind Rebuttal 16:21-17:2.]

The problem with these claims is that they simply do not reflect the undisputed facts, and, as I mentioned, rest on incorrect legal opinions that these witnesses recognize they are not competent to make. The PSA expired on December 31, 2005, according to an explicit provision in that contract. EEInc. owns the Joppa Plant's power, and has decided to exercise its legitimate right to sell that power at a market price. As Prof. Downs again emphasizes in his Surrebuttal

Testimony, AmerenUE has no legal right to compel any of EEInc.'s directors to violate their legal obligations by voting to sell EEInc.'s power at a below-market price. In our post-Enron environment, where corporate officers are being sent to jail for violating their duties to their corporations, it is truly amazing that anyone would suggest that these directors should sell Joppa Plant power, a critical EEInc. asset, for less than a market price to benefit another corporation in which they have an interest.

Q. How do these witnesses get around these facts and legal duties?

A. As Prof. Downs points out, with respect to their legal conclusions, they really don't. They simply assert that AmerenUE has a legal right to do as these witnesses wish, and that it is either imprudent or inequitable for AmerenUE not to exercise that legal right. But, as Prof. Downs has explained, this conclusion betrays a complete ignorance of corporate law principles, and is simply wrong.

Beyond spurious legal claims, though, these witnesses also attempt to draw incorrect or unfair characterizations from the facts that they believe will support their adjustment.

Q. What factual characterizations advanced by these witnesses do you believe are incorrect or unfair?

A. Mr. Brosch argues that "the Company's investment in EEInc. has been consistently treated as jurisdictional by this Commission in all prior rate cases because the long-term cost-based purchased power agreements obligating Missouri ratepayers to pay for the cost of the Joppa Plant output have been treated as jurisdictional." [Brosch Rebuttal 9:13-17.] Exactly what Mr. Brosch means by his use of the word "jurisdictional" is unclear. It is undisputed that EEInc. is a seller of power at wholesale, and counsel advises me that the FERC has *exclusive* jurisdiction over such wholesale sellers. Mr. Brosch does not address how his notion of something being "jurisdictional" fits with FERC's role at all. Mr. Schallenberg has admitted that EEInc. is not within the jurisdiction of the Commission to set retail rates [Schallenberg Deposition 92:17-19], though, not being a lawyer, he does not know whether EEInc. is within the exclusive jurisdiction of the FERC. [Schallenberg Deposition 92:13-15].

Moreover, Mr. Brosch says that "the Company's *investment* in EEInc. has been consistently treated as jurisdictional," but that is clearly wrong. AmerenUE's investment in the stock of EEInc. has never been included in its rate base; it has consistently been treated as a below-the-line investment. For example, the dividends AmerenUE receives from the earnings of EEInc. are flowed through to its shareholders in FERC Account No. 123.215, Investment in Subsidiary Companies. If EEInc. was an above-the-line investment as Mr. Brosch claims, any such dividends would be flowed back to ratepayers as a credit against the cost of service, which has clearly never been the case.

Here again, even Mr. Schallenberg concedes that the investment in EEInc.'s stock has not been treated as an asset in rate base. [Schallenberg Deposition 69:13-19.] The Joppa Plant is not a generating station within AmerenUE's rate base. AmerenUE has purchased power from that plant; it has not bought that plant. It appears that Mr. Brosch has attempted to obscure that difference.

Q. Aren't there considerable differences between owning capacity [in rate base] and buying capacity through a purchased power contract?

A. Yes. As detailed on Schedule MLM-2 attached to this testimony, there are a number of key differences between the rights, benefits, and obligations under a purchased power agreement and those for an owned-generating plant that is included in a company's rate base.

When AmerenUE constructs (or acquires) a generating plant and puts that investment into rate base, its primary purpose is dedicated to serving the retail customers of Missouri. The cost of service that is used to set the rates retail customers pay includes the full operating expenses for the plant, as well as a return *of* and a return *on* the Company's total investment in the plant based on a traditional utility capital structure of roughly 50% debt and 50% equity. Retail customers have first priority to power generated from a plant that is in rate base, and have such rights for the life of the plant.

Contrast this with the Joppa Plant, which was built for the primary purpose of providing electric power in support of the nation's defense effort for the Government's Paducah uranium enrichment facility. AmerenUE's investment in the capital stock of EEInc. is not included in rate base. The power contract between EEInc. and the Sponsoring Companies provided the Sponsoring Companies with economical power for their systems to the extent that the Government did not use the Joppa Plant power. The cost of service that is used to set the rates AmerenUE's retail customers pay included charges for energy and capacity, as prescribed in the PSA, as a purchased power cost. The formula by which the energy and capacity charges were calculated included operating expenses from the Joppa Plant, as well as components based on a return *of* and a return *on* the EEInc.'s total investment in the Joppa Plant, but also reflecting EEInc.'s highly leverage capital structure. Mr. Schallenberg in his deposition chose to ignore these differences when trying to compare AmerenUE's Taum Sauk Plant and EEInc.'s Joppa Plant.

Q: Are there other factual mischaracterizations these witnesses make that obscure important distinctions between the various entities related to AmerenUE?

A: Yes. In his effort to justify his claim that AmerenUE could still get below-market priced power from EEInc., in his deposition, Mr. Schallenberg attempted to equate the relationship between Ameren Services Company (AMS) and AmerenUE with the relationship between EEInc. and AmerenUE. He was trying to use this comparison to justify his notion that a director can take one corporation's assets for the benefit of another corporation.

As Mr. Schallenberg should know, AMS was established in 1998 following this Commission's approval of the merger between Union Electric Company and Central Illinois Public Service Company to form Ameren Corporation, a merger which contemplated the formation of a service company (AMS) that would exist solely for the purpose of providing services to subsidiaries of Ameren Corporation, including AmerenUE. AMS was formed, like the service companies of many other public utility holding companies who were at the time regulated by the Securities and Exchange Commission under the Public Utilities Holding Company Act of 1935 (PUHCA). The PUHCA requirements were quite prescriptive in terms of which services were or were not allowed in a services company and how such costs were accounted for and charged to the affiliates receiving those services. AMS was not formed as a standalone business with a purpose apart from providing what are essentially at-cost services to Ameren Corporation affiliates. While PUHCA has been repealed, Ameren has continued this price structure of AMS, which is consistent with this Commission's Affiliate Transaction rules. In short, AMS was not, is not, and cannot be a for-profit entity, and has no market for its services.

EEInc. is a separate, for-profit corporation formed for a particular purpose that operates in a market-based environment. It was never restricted to selling its products at cost, or to selling them solely to its shareholders. For most of its history, a majority of its shares were owned by non-Ameren entities. It has a market for its products (its power), and it has an ability to produce a profit for its owners. It is subject to the exclusive jurisdiction of the FERC, which has granted it market-based rate authority. In short, it is fundamentally different than a service company with captive customers to whom services are, by the very nature of the service company, provided at-cost.

Q. Does the existence of the now-expired PSA confer some right for AmerenUE to command EEInc. to sell power at a below-market price?

A. It cannot. The cost of *any* prudently-incurred power purchase will be recovered in retail rates. This is the typical and routine treatment of power purchase costs. The purchaser gets value for his money (the electricity), but does not get, as well, some right to compel the seller continue to sell the power at the same price as long as the buyer wishes. For example, the purchase of firm power by AmerenUE from Arkansas Power & Light (AP&L) would not and did not give AmerenUE ratepayers ongoing "rights" to a preferred price for power from AP&L's generating plants beyond the term of the contract.

No one disputes that the PSA was a prudently incurred power purchase agreement. Indeed, the fact that some parties now claim that it was somehow improper for AmerenUE not to continue that contract confirms that it was a good deal.

Q. But wasn't the PSA different from these other purchased power contracts? Mr. Brosch states that "Under these long-term power sale arrangements, prices were set and adjusted based upon full cost recovery, including a full return on and return of capital invested in the Joppa Plant. Owning the stock in EEInc. represented little if any risk of loss to the owners, given these power sale arrangements and the financial guarantees and

repayment commitments that were secured by AmerenUE, with Commission approval." Does this make a difference?

A. The PSA did contain pricing formulas that allowed EEInc. to obtain full cost recovery, but again, this is not unusual for firm-power contracts. Such contracts typically provide for prices that allow for full cost recovery, so that hardly makes the AmerenUE-EEInc. transaction unique. Indeed, Mr. Schallenberg has acknowledged that the capacity and energy charges of a firm power contract like the PSA cover all variable and fixed costs of producing power, and that one of those fixed costs is a return on and return of capital. [Schallenberg Deposition 85:14-16.]

Moreover, it is quite a leap of logic to assume that EEInc.'s owners bore little if any risk of loss simply because of the pricing provisions in their contracts. Risk, by its very definition, is simply the possibility of something happening. History has shown that the Joppa Plant has not experienced any extraordinary costs/problems. However, if such an event had happened, a pricing provision in a contract in of itself does not mitigate or eliminate the potential of loss to EEInc.'s shareholders. If a catastrophic event had happened, full cost recovery from ratepayers could not have occurred. Here again, because the investment in EEInc. is below-the-line, AmerenUE would not have asked for recovery of such costs, and it certainly would not have been entitled to such a recovery from ratepayers. Even if AmerenUE sought such a recovery, this Commission clearly would not have allowed it. Mr. Brosch offers no basis for his claim that this risk somehow passed to AmerenUE's ratepayers. All AmerenUE ratepayers were ever responsible for were the dollars paid by AmerenUE for the energy and capacity AmerenUE bought to serve those ratepayers.

Q. Similarly, Mr. Brosch states "There has been no demonstration by AmerenUE that its shareholders ever absorbed any significant risks, costs or losses associated with Joppa that were not fully mitigated by long-term power supply agreements and other financial guarantees extended by EEInc.'s utility sponsors." [Brosch Rebuttal 12:7-10.] Is this a proper characterization of the facts?

A. No. Risk represents the future potential or probability for bad things to happen. One can mitigate risk or hedge against risk, but what is absorbed are losses associated with actual negative events or the gains arising from favorable outcomes. The fact of the matter is that shareholders of EEInc. did *bear* risks, and the fact that those risks did not in fact materialize into major losses does not diminish that fact.

Q. Have the shareholders of EEInc. absorbed any losses associated with their equity investment in EEInc. that were not mitigated by, or recoverable through, the PSA?

A. Yes. As I mentioned in my Rebuttal Testimony, EEInc.'s shareholders have absorbed losses associated with the sale of Midwest Electric Power's capacity and losses recorded in 2002-04 associated with the abandoned project to construct a coal transfer terminal.

Q. How do you respond to Mr. Brosch's statement, "Under the principal that financial rewards should accrue to the party absorbing risks and cost responsibility for an investment, shareholders should not be allowed to now reap windfall profits, simply by removing the Joppa Plant from Missouri jurisdictional ratemaking" [12:11-13]?

A. I believe Mr. Brosch's use of the phrase "reap windfall profits" is simply an inflammatory phrase made to imply some illicit or illegal act, neither of which is true. If Mr. Brosch is attempting to imply that AmerenUE ratepayers have somehow incurred risks by virtue of their power contract with EEInc., he is once again mistaken. If one were to buy into the notion that a power contract somehow conveys rights beyond receiving power paid for, even then AmerenUE ratepayers did not come close to bearing risk in proportion to AmerenUE's ownership interest in EEInc. As pointed out elsewhere in my Rebuttal Testimony and in this Surrebuttal Testimony, over the life of the various purchased power agreements AmerenUE ratepayers have only paid for about 16% of the total Joppa Plant power. Even when you split the price for the Joppa Plant power into demand and energy charges, as shown on Schedule MLM-3, attached to this testimony, you can see that AmerenUE's share of Joppa's demand (or fixed) charges was only about 18%. The remaining 82% of demand charges, and 84% of the total purchases of Joppa Plant power, were charged to and paid by the DOE and the other Sponsoring Companies. Finally, AmerenUE's historical recovery of the cost of power purchases from EEInc. in its Missouri-jurisdictional retail revenue requirement does not change the fact that Missouri does not have jurisdiction over EEInc. or the Joppa Plant itself.

Q: Q: Obviously a power contract does not somehow convey rights beyond receiving the power that was paid for under the contract. However, even if one bought into the notion that it did, are the adjustments proposed by others correct?

A. No. The approximately $80 million adjustment advocated by Staff and the state is significantly overstated.

Q: Please explain.

A: A comparison of the Company's PROSYM production cost modeling (with and then without including power from EEInc.) suggests roughly a $79 million impact on energy costs. However, these energy costs must be netted against the demand charges that would need to be included in the Company's cost of service if AmerenUE were, in fact, receiving power from EEInc. A rough estimate of such demand charges, based on adjusted 2005 actual demand charges would be about $35 million. And one could reasonably expect that actual demand charges would increase further from the 2005 level. Thus, the net effect of Staff's proposed adjustment would be somewhere closer to the $40 million - $45 million range than the approximately $80 million adjustment currently advocated by Staff and the state.

Q. Are there other factual mischaracterizations of the PSA on which the other parties rely?

A. Yes. Mr. Schallenberg states that "EEInc. was not operated as a below-the-line investment and its debt was primarily supported by the purchase power payments paid by Union Electric and its customers, not the equity investment by Union Electric. The Power Supply Agreements were critical to the operation of EEInc. due to the owner decision to finance EEInc. with high debt levels and minimal equity investments. Union Electric received in rates from its customers rate treatment similar, if not better, for its share of the Joppa generating station as the other generating units owned by Union Electric. These payments were based on the ownership of the plant as well as a fifteen (15%) return on equity." [Schallenberg Rebuttal 6:19-26.]

Here again, Mr. Schallenberg is trying to invest perfectly normal aspects of a purchased power contract from that time with an unheard-of significance. EEInc. was a below-the-line investment of AmerenUE's shareholders. The expense of the prudently incurred PSA was recovered in retail rates, again as is normal practice, and that did not transform EEInc. into an above-the-line investment.

As to the statement about the debt being "primarily supported" by the purchased power payments made by AmerenUE and its customers, the facts simply do not support this claim. The majority of the costs supporting the Joppa Plant, be they fixed costs or fuel expenses, were recovered by EEInc. through power sales to the Federal Government and the other

Sponsoring Companies. In the aggregate over the period 1954-2005, as shown on Schedule MLM-3, AmerenUE customers' rates have included charges for power that would cover at most about 16% of the total Joppa-related costs. And since interest expense on debt is only one component of fixed costs and power costs charged to AmerenUE ratepayers have covered at most about 18% of Joppa's fixed costs, it is impossible to understand how Mr. Schallenberg can claim that AmerenUE ratepayers have "primarily supported" EEInc.'s debt.

Mr. Schallenberg continues to focus on the 40% of EEInc. stock owned by AmerenUE, which had no direct relationship with the money AmerenUE actually spent to buy EEInc.'s power. The fact that the price AmerenUE's customers paid for EEInc.'s power, including a return of and a return on capital, and that AmerenUE owns 40% of EEInc.'s stock does not convey an ownership-like responsibility for the costs or debts of EEInc. onto AmerenUE's customers. This fact is illustrated by Schedule MLM-2. Indeed, the different consequences for AmerenUE of buying power from EEInc. as an unregulated entity, and owning a percentage of EEInc. that is included in rate base, underscores the fact that AmerenUE's ratepayers did not bear any kind of unique risk or otherwise "support" EEInc. in some unique way. If EEInc. were really "jurisdictional" (that is, somehow part of AmerenUE's rate base) as these other parties contend, Schedule MLM-3 shows that AmerenUE's ratepayers would have paid for power that covered 40% of EEInc.'s costs, not the approximately 16%. As that schedule shows, if the 40% interest in EEInc. really had the significance that these other parties claim, AmerenUE's Missouri cost of service would have included roughly $800 million to pay for the Joppa capacity charges, irrespective of the electricity ratepayers received in return, as opposed to the roughly $350 million included in that cost of service for which those ratepayers actually received electricity.

Yet it is important not to forget that purchased power contracts for firm power are priced to recover all of the costs (i.e., both fixed and variable costs) of the producing that power. Indeed, the price of any commodity must cover the cost of producing or procuring it. (If it didn't, the seller would soon go out of business.) The cost of borrowing money to build a plant to produce power (or anything else) is a cost of producing power. A pro-rata share of that cost will of course be included in the price of a purchased power contract for firm power. In that sense, every purchaser of firm power is "supporting" the debt of the seller. But it is simply verbal game-playing to say that a purchase power contract for firm power gives the buyer some right to compel the seller to sell at below-market prices after the contract expires.

Q: Is there any evidence that the ROE included in the PSA was imprudent?

A: No. The 15% ROE included in the pricing formula in the PSA certainly cannot justify Mr. Schallenberg's claim that AmerenUE received "similar, if not better" rate treatment of its ownership share of Joppa Plant than with its other owned generating units. First, as he acknowledged in his deposition, there has been no claim that the 15% ROE was imprudent. [Schallenberg Deposition 86:22 – 87:5.] Moreover, the 15% ROE included in the pricing formula in the PSA is applied to a much smaller equity component than would be the case under traditional utility ratemaking utilizing a more typical utility capital structure. Again, in his deposition, Mr. Schallenberg acknowledged that an increase in the amount of debt leads to an increase in the financial risk. [Schallenberg Deposition 59:12-15.]

Q. Mr. Schallenberg states that Staff's position is that AmerenUE engaged in an imprudent decision to sell the capacity and energy associated with its 40% ownership of EEInc. into the open market instead of using this capacity and energy to meet its obligations to its Missouri customers at cost-based rates. AmerenUE's decision was based

on the fact that AmerenUE could make more money by selling power into the Illinois market than it could from selling its power to its Missouri customers. [Schallenberg Rebuttal 16:21-17:4.] How do you respond to their position?

A. This is one of Mr. Schallenberg's more outrageous statements, combining a factual mischaracterization with a legal judgment he is not competent to make (and which Prof. Downs shows is wrong). AmerenUE did not decide to sell Joppa power into the open wholesale market. This was EEInc.'s decision and action. If Staff was so opposed to EEInc. having the ability to sell Joppa's output at market-based rates, why didn't the Commission itself contest EEInc.'s market-based rate (MBR) filing at FERC? With MBR authority, EEInc. has both the right and fiduciary obligation to its shareholders to sell the Joppa Plant's output at market rates, as Prof. Downs has testified.

Q: Mr. Schallenberg then goes on to state "the MPSC must authorize AmerenUE to charge Missouri customers higher rates to reflect the increased cost of service caused by AmerenUE incurring (1) higher fuel and purchased power costs to replace the energy formerly provided by the Joppa unit and (2) lower levels of off-system sales that offset AmerenUE's electric operation costs." [17:5-9.] Is that correct?

A: No. The point I think he misses is that the Joppa Plant sells power only at wholesale and, as such, is under FERC's exclusive jurisdiction and is selling its output at market rates under a FERC-approved tariff. This Commission does not have to authorize anything in this regard.

Q: Mr. Schallenberg follows this up with the statement that "Missouri consumers should not be burdened to pay higher costs that AmerenUE would avoid if dealing with a non-affiliated entity." [Schallenberg Rebuttal 17:14-16.]

A: I am a little confused by this statement. If he is attempting to argue that a non-affiliated entity would sell power to AmerenUE at a below-market rate, his assertion is absurd and totally unfounded. If he is implying that because EEInc. is an affiliate of AmerenUE that it should be required to sell to AmerenUE at prices below those it could realize by selling to non-affiliates in the open wholesale power market, then he again misses the point of EEInc. being under FERC jurisdiction and authorized to sell power at market-based rates.

Q. As a further part of his effort to deny the different regulatory world we are in now, in his deposition, Mr. Schallenberg disputes the assertion that, in 1987, when EEInc. entered into the PSA with AmerenUE and the other sponsoring companies, there was no market for wholesale power. [Schallenberg Deposition 50-51.] Is he correct?

A. It is true that utilities have long entered into bilateral wholesale power transactions for the sale of various generation products, including firm power and non-firm or economy power. However, as of 1987 there was, at best, a very limited "market" for wholesale power. At that time, there wasn't an organized regional wholesale power market such as exists today; *i.e.*, the market administered by the MISO. MISO began offering transmission service under its own tariff on February 1, 2002, and did not offer a formal spot market for wholesale power (known as the "Day Two Market") until April 2005. In addition, 1987 significantly pre-dated critical legislative and regulatory developments that facilitated the formation of competitive wholesale power markets, such as the Energy Policy Act of 1992 (which gave FERC expanded authority to order the provision of transmission access) and FERC's Order 888, issued in 1996, which required all FERC-jurisdictional utilities to provide open transmission access and to functionally separate their transmission operations from their wholesale power sales activities.

Mr. Schallenberg's attempt to deny that the world has changed drastically in just the last few years is belied by the testimony of Staff witness Michael Proctor in the Metro East case (Case No. EO-2004-0108). In that case, Dr. Proctor noted the difficulty (as of April 2004) of establishing a market price for transactions between AmerenUE and AmerenCIPS under the now-terminated Joint Dispatch Agreement. That difficulty existed because there was at that time no transparent wholesale energy market in the region. Dr. Proctor testified that "it would be very difficult to do the transfers at market price" because there "wasn't a transparent market for energy." Case No. EO-2004-0108, Tr., Apr. 1, 2004, p. 928, l. 17-19. In referring to a 'transparent market' Dr. Proctor was referring to "a market where the price at which electricity sells is determined by an independent market facilitator and that price is published for everyone to see." *Id.* p. 4, l. 4-9. Dr. Proctor also confirmed that such a market did not exist at that time, and that it might not arise until sometime after December 1, 2004: "Q. When do you believe such a transparent market will come into being, if ever? A. December 1st, 2005. Q. And what is the significance of December 1, 2005? A. That's when the day-two markets at the Midwest ISO are planned to begin." *Id.* p. 930, l. 2-8. Dr. Proctor later corrected his reference to December 1, 2004. We now know those markets did not start until April 1, 2005.

The fact is that the world changed drastically for EEInc. once the transparent wholesale market truly emerged, and EEInc.'s directors then, properly according to Prof. Downs, acted in EEInc.'s interests by recognizing the new world in which EEInc. was operating to sell EEInc.'s power into the newly created market available to EEInc.

Q. But is Mr. Schallenberg correct when he claims that there were negotiated deals for wholesale power in the late 1970s and early 1980s in which capacity was sold below its cost because of a glut of capacity in the Midwest region?

A. Mr. Schallenberg cites no examples but may well be correct that, in certain wholesale transactions, capacity was sold at a discount from its cost of service during the late 1970s and early 1980s.

Q. Would it be appropriate to characterize such sales as market-based sales?

A. Absolutely not, because no firm had authority to sell power at market rates during the time period cited by Mr. Schallenberg. All wholesale power sales during the late 1970s and early 1980s were made at cost-based rates, though FERC did permit utilities some flexibility to sell capacity at below-cost rates to facilitate sales when there was excess capacity in a region.[1] However, selling capacity at a "discount" from its average or embedded cost is still selling at a cost-based rate, because the price is based on the seller's cost.

Market-based rate authority, by contrast, allows a generator to sell power at a price above its cost. Absent such authority, a generator could not sell power for more than its cost. Since it has been granted market-based rate authority by FERC, EEInc. is permitted to sell energy and capacity from the Joppa Plant at market prices, which now exist as a result of the advent of the MISO's Day Two Market. Current market prices exceed the Joppa Plant's costs. This is the core of the dispute between AmerenUE and Staff and the other parties who believe that EEInc. should continue to sell power to AmerenUE at the Joppa Plant's cost of production.

Q: Mr. Kind attaches a Kentucky Utilities (KU) FERC filing in Docket No. ER05-1482-000 as an Attachment to his testimony and argues that UE would have devoted the Joppa Plant to serving its native load customers if it felt the same public interest obligations and desire to comply with state commission resource planning rules as KU. [Kind Rebuttal 16:17-23.] Is Mr. Kind's assessment correct?

[1] See, Wilbur C. Early, Coordination Transactions among Electric Utilities, *Public Utilities Fortnightly*, September 14, 1984, pp. 31-37 at 35.

A: No. Mr. Kind states "the Directors of KU were making their best efforts" to negotiate an extension of the PSA at cost-based rates. However, the section of the FERC filing he references simply states that "KU is attempting to negotiate" such an agreement. There is nothing to support the suggestion that it was "KU's" EEInc. board members who were doing the negotiating In reality, as Prof. Downs states, members of the Board of Directors of EEInc. have the same fiduciary responsibility in looking out for the interests of EEInc. regardless of their primary corporate affiliation.

Furthermore, if we look at the same FERC filing referenced by Mr. Kind (FERC Docket No. ER05-1482-000), in the paragraph immediately above the reference Mr. Kind uses in his testimony can be found the following statement: "KU would like to submit a clarifying statement: KU cannot commit, and has not committed, to using the capacity presently available pursuant to the PSA between EEInc. and KU beyond the existing term of the agreement (i.e., December 31, 2005) because KU's contractual rights to that power expire on December 31, 2005." This statement shows that no matter what "KU's" representatives on the EEInc. Board of Directors said or how they voted, it was clear that KU fully recognized that their contractual rights to any Joppa Plant power at cost-based rates expired on December 31, 2005.

Lastly, I would point out that the Commission has jurisdiction over AmerenUE, not EEInc., and it would be hard for the Commission to find AmerenUE imprudent for not purchasing power at cost-based rates from a seller that is unwilling to sell power at such rates.

II. DSM Issues.

Q. Please summarize the points relating to the DSM programs you plan on addressing.

A. Both DNR and Staff support the use of a regulatory asset account to provide cost recovery for DSM expenditures.

DNR witness Brenda Wilbers recommends that the Commission set DSM goals as a percent of growth for both demand and energy. In order to achieve these goals, she recommends that AmerenUE commit to DSM funding to a minimum funding level of $10 million per year and ramping up to $20 million per year.

MPSC witness Lena Mantle supports the concept of DSM goals as a percent of growth without a minimum expenditure attached to the goals. Rather than goals with specific spending amounts, she advocates letting the planning process defined in the Commission's Electric Utility Resource Planning Rule (Chapter 22) determine the spending levels.

As I stated in my Rebuttal Testimony, I agree in principle with the concept of using a regulatory asset account (RAC) to address DSM cost recovery issues. Generally, I agree with both witnesses. DSM goals for both capacity and energy are important.

I definitely believe that the overall spending level for DSM resources should be determined through a resource planning process consistent with Chapter 22. Yet, committing to a *reasonable minimum* DSM spending goal does not have to undermine the integrity of the resource planning process. As long as the minimum spending level is rational and supported by industry experience, it can serve as good faith commitment for all parties.

Only DSM programs that are cost effective and support the Company's resource planning objectives should be implemented. DSM programs should not be implemented solely to satisfy a dollar spending requirement.

A. <u>Status of AmerenUE's Resource Planning Process.</u>

Q. Above you mentioned the Commission's Electric Utility Resource Planning Rule (Chapter 22). What is the status of the planning process for AmerenUE?

A. On December 5, 2005, AmerenUE filed its first Integrated Resource Plan (IRP) with the Commission in over a decade. For over a year, the parties tried to reach an agreement addressing various concerns with the filing. Eventually, a Stipulation and Agreement was reached and was approved by the Commission.

Q. What is the most important element of the Stipulation and Agreement?

A. During the year of working with parties to resolve concerns, it became apparent that the root cause of most issues was the lack of participation of stakeholders in the planning process itself. In my opinion, this is one of the most significant flaws in the dated Chapter 22 Rule.

The rule requires that utilities develop a resource plan and file it with the Commission every three years. After the utility files its plan, parties have one hundred twenty (120) days to file a report with perceived deficiencies. In today's regulatory environment, it is unlikely parities will be able to reach consensus in such a non-participatory process. Because of this realization, AmerenUE approached parties with the concept of performing the next resource plan in a "participatory" process.

We are most appreciative of the time and effort that stakeholders have committed to the participatory planning process. There is no question in my mind that stakeholders have opened our eyes to new possibilities to consider in the areas of demand-side management, environmental risk and uncertainty and load analysis and forecasting. As we expand into other resource planning areas including renewable energy and other supply side options, we expect to continue to expand our thinking as a result of stakeholders' insights into the planning process.

Q. Has the "participatory" IRP process begun? If so, is it working?

A. It has begun and it is working. I would say it is working on two levels. First, AmerenUE has held five workshops with parties: two addressing Demand-Side Resources, two addressing Environmental (and Risk) Analysis, and one addressing Load Analysis and Forecasting. Currently, two more workshops are scheduled: one for Environmental (and Risk) Analysis and one for Load Analysis and Forecasting.

On a second, and more important level, parties have been working together to improve the planning process by defining potential waiver requests. In addition to discussing the process and analysis, parties are working to build a common understanding on assumptions, inputs, and potential resources.

Q. Do you believe the process will lead to meaningful levels of demand-side resource initiatives? If so, why?

A. Without a doubt, this process will lead to a meaningful level of DSM initiatives. By including all interested parties up-front, we are able to take advantage of everyone's insight and utilize their experience in building a robust preferred resource plan that includes meaningful commitments to demand-side resources.

The success of the "participatory" process hinges on everyone's commitment to the process. It is not just AmerenUE. All parties have to be committed to spending significant time and effort at the beginning of the process. The real key is the effort spent early in the process, rather than at the end, when it is too late.

Q. By following the "participatory" process and schedule outlined in the Stipulation and Agreement, when will AmerenUE be ready to specify its DSM implementation plan?

A. I anticipate preliminary demand-side resource plans will be ready at the end of the "Pre-Integration Analysis" Phase outlined in the Stipulation and Agreement. This means sometime in May-June 2007. These initial plans will consist of demand-side programs that are identified as cost-effective in the preliminary screening. At that time, parties will have an initial feel for the level of demand-side resources that can be cost-effectively implemented for AmerenUE.

The plans will then be integrated with supply-side options and analyzed. After the integration analysis, the top plans will be subject to the risk analysis. After the risk analysis, AmerenUE will be ready to state its updated preferred resource plan. This will be at the end of the Risk Analysis Phase or around December 2007.

B. Demand-Side Resource Funding Level.

Q. It is obvious from your testimony that you support the IRP process determining the absolute spending level for demand-side resources. But, above you also indicate that a reasonable minimum spending level goal may be appropriate. Why is that?

A. The final spending level for demand-side resource should be determined through the Integrated Resource Planning process that is governed by Chapter 22. But, a minimum spending level that is rational and supported by industry experience can serve as good faith commitment for all parties. If done in this manner, a reasonable minimum DSM spending goal will not undermine the integrity of the resource planning process.

Q. Do you support DNR witness Brenda Wilbers' suggestion that AmerenUE commit to DSM funding that begins at $10 million per year and ramps up to $20 million per year?

A. For the most part I support Ms. Wilbers' suggestion that AmerenUE commit to ramping demand-side resource expenditures up to 1% of annual sales revenue (or $20 million). There may be some areas for discussion about the starting point and the ramp rate at which to get to 1%. I am confident that we can reach an agreement.

According to the American Council for an Energy Efficient Economy (ACEEE) in its review of all 50 states, the nationwide average for electric energy efficiency program spending was 0.52% and only 13 states exceeded 1%.[2] The ramifications of starting at 1% are that AmerenUE's minimum spending level would be among the highest in the nation without any analysis as to the cost-effectiveness of that spending level.

Q. You indicate support for a reasonable minimum spending level goal. Can you suggest what that minimum spending level should be and your justification?

A. The ACEEE indicates that the nationwide average for electric energy efficiency program spending is 0.52%. The top 13 states spend between 1% and 2% of annual revenues on DSM programs. The next top 16 states spend between 0.1% to 1% of annual revenues on DSM programs.

I suggest that a reasonable minimum DSM budget goal for AmerenUE should start at the national average of 0.52% of annual revenues. For AmerenUE, which has annual electric revenues in the $2.5 billion range, 0.52% times $2.5 billion equates to a beginning DSM annual budget goal of approximately $13 million. Furthermore, I suggest that the minimum annual budget goal ramp-up to $20 million or 0.8% of annual AmerenUE revenues by 2010.

Q. Why do you suggest a ramp-up period?

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[2] The nationwide average for electric energy efficiency program spending as a percentage of total utility revenues is 0.52%. Thirteen states exceed 1% by this measure. The highest (Vermont) is 3.0%. Twenty-three states spend less than 0.1%. (ACEEE's 3rd National Scorecard on Utility and Public Benefits Energy Efficiency Programs.)

A. We will increase the funding levels as we build the infrastructure to assist all classes of customers in becoming more energy efficient. Providing for a ramp-up period for the minimum expenditure goal allows for development of the appropriate infrastructure for program delivery. Yet, it is aggressive enough to assure a meaningful commitment.

Q. Do you anticipate that this suggested minimum place an arbitrary cap on spending?

A. No. My suggestion is not for an expenditure cap. Rather, it is for a reasonable minimum spending goal that provides all parties with assurance that the Company is committed to funding DSM programs at a reasonable level.

Q. Do you anticipate that this suggested minimum would result in DSM programs being implemented solely to meet a dollar spending requirement?

A. No. The programs that get implemented will still be determined by the Commission's Electric Utility Resource Planning Rule (Chapter 22) and they will have been shown to be cost-effective. However, as I state above, it seems reasonable to expect that AmerenUE's cost-effective programs would result in a minimum expenditure equal to the national average.

We recognize that successful incorporation of energy efficiency into the resource planning process requires utility executives, resource planning staff, regulators, and other stakeholders to value energy efficiency as a resource, and to be committed to making it work within the integrated resource planning process. Consequently, our goal of budgeting a minimum of $13 million per year on DSM is intended to show AmerenUE's good faith that we will commit to invest significant dollars to fund cost-effective DSM programs that result from the IRP process.

Q. What else is AmerenUE doing to demonstrate its commitment to DSM?

A. AmerenUE is investing significant time on the part of employees and contractors to develop DSM opportunities. I've already discussed the DSM planning process and the associated DSM workshops with stakeholders. We have also moved the Products & Services group to the Corporate Analysis department. The Products & Services group will, among other assignments, be responsible for DSM program management at AmerenUE.

III. Emission Allowances.

Q. AmerenUE witness James C. Moore II addresses most of the issues raised by Mr. Kind in his Rebuttal Testimony relating to emission allowances, and Mr. Moore has responsibility for executing emissions allowance transactions involving AmerenUE's emissions allowance bank generally. Why are you filing Surrebuttal Testimony relating to the emission allowance issues addressed by Mr. Kind in his Rebuttal Testimony?

A. I am filing Surrebuttal Testimony to address the facts relating to an adjustment Mr. Kind seeks to make to 2005 allowance sales revenues because I have direct knowledge of a transaction Mr. Kind incorrectly relies upon as support for his adjustment. I am not involved in day-to-day management of AmerenUE's allowance bank, but as one of a few officers that were in the office when the subject transaction was closed, I assisted Mr. Moore in contacting the counterparty, Dynegy, on this transaction, and therefore I am aware of the facts relating to it.

Q. What is Mr. Kind's contention, as you understand it?

A. As Mr. Moore discusses in his Surrebuttal Testimony, Mr. Kind implies, incorrectly, that AmerenUE, in 2005, sold allowances to Dynegy for an average price of $175 per ton at a time when the market for allowances had shot up to approximately $1,475 per ton. Based upon his error, Mr. Kind then suggests that the actual 2005 allowance revenues for purposes of calculating his average allowance revenues over the past five years should be increased by nearly $20 million.

Q. Please explain the transaction at issue.

A. As Mr. Moore explains, in 2001 AmerenUE sold Dynegy *call options* under which Dynegy could, until December 1, 2006/ December 3, 2007, buy allowances at strike prices that averaged $175 per ton. On the dates that the call options were sold, in 2001, the market price for allowances was just $124.74 and $104.19 per ton, respectively, meaning AmerenUE realized a substantial premium when the options were sold. In fact, for several years prior to the sale of these call options, the allowance market had been very flat and it continued to be flat for two or three years beyond 2001. This is shown by Mr. Kind's graph at page 15 of his Rebuttal Testimony. As Mr. Moore also explains, new environmental regulations proposed in 2004 created a drastic run-up in allowance prices. Prices are still much higher today than they were in the late 1990s and early 2000s, but they have come down substantially.

Q. Mr. Kind portrays the 2001 Dynegy option sale as a transaction that occurred in 2005. Please explain.

A. Mr. Kind fails to mention that the call options were sold in 2001. Consequently, in 2001 the call options fixed AmerenUE's legal obligation to sell allowances to Dynegy at the prices contracted for at that time (i.e., at the strike price) which was at an average price of $175 per ton. The only "transaction" that occurred in 2005 was Dynegy's exercise of the options, which AmerenUE obtained by paying Dynegy a $634,919 early exercise fee. Dynegy's early exercise took place on December 21, 2005. Because, since December 21, 2005, the market for allowances has never been below the $175 average price agreed to in 2001, there is no doubt that

Dynegy would have exercised these options no later than their expiration date. Consequently, the only cost to AmerenUE was the comparatively small $634,919 early exercise fee.

Q. Why did AmerenUE pay the early exercise fee?

A. Under accounting rules in place by 2005, options had to be "marked-to-market," meaning they produced undesirable and ongoing earnings volatility for AmerenUE. That volatility could be eliminated upon the early exercise of the options by Dynegy.

Q. Mr. Kind suggests that this mark-to-market differential should, in effect, be imputed to the Company as additional allowance revenues in 2005, which has the effect of increasing Mr. Kind's "normalized" level of SO2 allowance revenues he recommends be included in base rates. Do you agree?

A. Absolutely not. AmerenUE could not, as Mr. Kind alleges, "generate" much greater revenues from the allowances that AmerenUE had to sell at an average price of $175 to Dynegy. AmerenUE was *contractually obligated* to sell these allowances to Dynegy at an average price of $175 per ton. When the decision to sell the call options was made in 2001, the price AmerenUE received from the sale was quite favorable (about 50% above market at the time). Conditions changed due to newly proposed regulations, and this particular deal did not go AmerenUE's way. However, as Mr. Moore explains in his Surrebuttal Testimony, AmerenUE's overall management of its allowance bank has brought huge value for ratepayers, and that value can particularly be captured on a going-forward basis if the Commission orders the establishment of a regulatory liability so that future revenues from the sale of allowances can be used to offset future environmental capital expenditures, a proposal the Company has indicated is good regulatory policy. Mr. Baxter outlines this proposal in his Rebuttal Testimony.

Q. How does any of this affect the revenue requirement in this rate case?

A. It shouldn't, unless the Commission thinks it is sound policy to build a very high level of allowance revenues into base rates thereby creating a need for the Company to sell that many allowances each and every year just to have an opportunity to earn a reasonable return on equity. None of this discussion has any relevance whatsoever if, as the Company has proposed, all SO2 allowance revenues from sales after rates set in this case go into effect are held as a regulatory liability that is then used exclusively to defray future environmental expenditures. As Mr. Baxter explained in his Rebuttal Testimony, creating this regulatory liability, largely as Staff itself has suggested, is the most reasonable way to deal with allowances on a going-forward basis, will remove the potentially contentious and uncertain exercise of trying to determine what a "normalized" level of allowance sales is for purposes of setting rates, and will dedicate all allowance revenues to paying for the very large capital expenditures faced by AmerenUE in the coming years for environmental compliance at its coal-fired generating stations. Mr. Moore also addresses these issues in his Surrebuttal Testimony.

Q. Why does Mr. Kind talk about "affiliate abuse" and cite to the Commission's affiliate transaction rules.

A. Incorrect documentation relating to the early exercise of Dynegy's call options may have created a misconception in Mr. Kind's mind about what actually occurred in 2005. As Mr. Moore explains in his Surrebuttal Testimony, because AmerenUE was required to pay a $634,919 early exercise fee so that Dynegy would exercise these options in 2005, Mr. Moore believed he should obtain appropriate management approvals to spend that sum.[3] Mr. Moore

[3] Given that establishing a regulatory liability on a going-forward basis moots any issue relating to what the level of allowance revenues were in 2005 or any other of the last five years used by Mr. Kind to calculate his "normalized" level of allowance revenues, there is no ratepayer detriment associated with AmerenUE's payment of the early exercise fee. However, if one were to calculate a normalized level of allowance revenues that included 2005 revenues, the Company agrees that the early exit fee should in effect be imputed to AmerenUE as additional allowance revenues because the early exit fee ultimately benefited Ameren Corporation's earnings by removing the

therefore prepared an approval document (Attachment 4 to Mr. Kind's Rebuttal Testimony) and in it stated that Dynegy's early exercise was "contingent upon considerations in a reactive power case Andy Serri is involved in." As Mr. Serri states in response to OPC DR 2213HC (attached hereto as Schedule MLM-4), he was involved in no such case. As Mr. Moore explains in his Surrebuttal Testimony, he was simply wrong with respect to his reference to Mr. Serri or a reactive power case.

Q. Why would Mr. Moore make such a mistake?

A. I believe he became confused because Mr. Serri assisted me in reaching a responsible person at Dynegy about exercising the option. It was my understanding at the time that Mr. Moore had been asked by his superiors to see if Dynegy would exercise the options early, for the reasons I outlined earlier. Mr. Moore contacted me shortly before Christmas 2005, at a time when a number of senior executives were out of the office for the holidays, to see if I might be able to get in touch with someone at Dynegy because Mr. Moore was having trouble getting a call back from Dynegy. I did not have a contact at Dynegy, but I was aware that Andy Serri might have such a contact. At the time, Mr. Serri's job responsibilities included his role as President of Ameren Energy, which acted on behalf of AmerenUE in selling its excess power. Mr. Serri put me in touch with an appropriate person at Dynegy and was in my office at the time I talked to the Dynegy representative since I did not know him. During my contacts with Dynegy, they indicated that they might be willing to exercise the options, but they wanted to talk to someone at Ameren about two transmission cases involving Illinois Power Company d/b/a AmerenIP which neither myself nor Mr. Serri knew anything about. It was Dynegy that linked resolving those two cases to early exercise of the options. I contacted AMS' Vice President of

volatility associated with the mark-to-market requirements of the accounting rules. Consequently, the 2005 allowance revenues of $21,383,875 would be increased by $634,919 to $22,018,794.

Transmission, Maureen Borkowski, who I assumed would be familiar with the transmission cases. Ms. Borkowski communicated AmerenIP's position to me and I communicated that to Dynegy and the cases were resolved. Dynegy then exercised the options. Ms. Borkowski told me at the time that the payment they were able to get from Dynegy was fair and acceptable and that they did not have to discount the settlement payment to get Dynegy to agree to an early exercise of the options.

Somehow Mr. Moore incorrectly concluded that Mr. Serri was involved in a reactive power case and he apparently included the statement in Mr. Kind's Attachment 4 because of that misunderstanding.

Q. You mentioned the linkage of Dynegy's willingness to exercise the options early to two transmission cases in which Maureen Borkowski (not Andy Serri) was involved in. What can you tell us about those cases?

A. I have no personal knowledge about them other than that they involved Illinois Power Company, which Ameren had purchased earlier in 2005, and Dynegy. Ms. Borkowski describes the cases in her Surrebuttal Testimony. I do know that AmerenUE had already decided to seek early exercise of the call options by Dynegy before I or anyone acting on AmerenUE's behalf knew anything about these Illinois Power/Dynegy transmission cases. No one from Ameren brought these cases up when discussing the Dynegy call options; rather, Dynegy brought those cases up.

Q. What does this have to do with the Affiliate Transaction Rules?

A. I'm not an attorney, although Mr. Kind seems perfectly willing to draw legal conclusions in his reading of the Affiliate Transaction Rules, but I can say that AmerenUE did nothing that "preferred" any Ameren affiliate. AmerenUE wanted to get these options off of its books and realize what it could from getting Dynegy to exercise the options to offset the loss AmerenUE was required to take under the accounting rules. If anything, an Ameren affiliate (AmerenIP) provided assistance *to AmerenUE* by settling the cases. However, as Ms. Borkowski's Surrebuttal Testimony indicates, AmerenIP was able to settle those cases for a sum that it would have found acceptable without regard to AmerenUE's ability to get Dynegy to exercise these call options early. Consequently, there was no preferential treatment from any Ameren affiliate to any other Ameren affiliate, and certainly not from AmerenUE, the regulated utility, to another Ameren company.

Q. Mr. Kind also implies that some FERC rules might have been breached?

A. Again, I am not an attorney, but Mr. Kind's comments apparently stem from his belief that Mr. Serri was somehow involved in resolving a reactive power case that in fact Mr. Serri was not involved in. Thus, Mr. Kind's allegations are off base. First, Mr. Serri wasn't acting as a power marketer. Second, Mr. Serri wasn't involved at all.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes.

Comparison of Investment in Generation Plant

Rate Base Investment vs. Purchased Power Contract

Using the EEInc Power Contract as the Example

Issue	Above-the-Line Investment in Generation Assets (Rate Based Asset)	Below-the-Line Investment in EEInc. (Purchased Power Contract w/ UE)
Primary purpose	To serve Missouri retail customers	To serve DOE's uranium enrichment facility; Excess power available to the Sponsors, including Union Electric
Capital investment	40% of Joppa investment and replacements	UE shareholders' initial investment, with no additional investment
Capital structure	Typically 50%/50% debt/equity; Higher cost of capital – higher rates	94%/6% debt/equity; Lower cost of capital – lower rates
Return on rate base	Return on equity calculated on an ever changing rate base; Typical utility cap structure	Return on equity component fixed; Calculated on a small equity amount; Highly leveraged cap structure
Operating costs	Pay 40% of all operating costs	Pay only for what you use – $ for power
Unit output**	40% of the output, year round; When not needed for native load, excess power is available to sell in the interchange market with a credit to retail cost of service	Based on contract terms; Take capacity when it is most beneficial (at time of system peak); Take energy only when it is economical
Access to unit output	For the life of the unit	Access to unit output only during the term of the purchased power agreement; No ongoing rights after the termination date of the agreement
Decommissioning and/or demolition costs	Costs are recoverable through rates at the time of decommissioning	Formula allocation; Majority of costs recoverable from the DOE; Nothing outlined in PSA regarding charges to Sponsors; Charges, if any, responsibility of Sponsors, not ratepayers
Operating/economic risk	Recoverable through the ratemaking process	Risks are assumed by the equity shareholders of EEInc
Summary of Joppa total costs*		
Demand (fixed)	$800.8 million (40.0%)***	$351.7 million (17.6%)
Energy (variable)	$1,190.9 million (40.0%)	$450.6 million (15.1%)
Total costs	$1,991.7 million (40.0%)	$802.3 million (16.1%)

NOTES

* Based on EEInc. power contracts with AEC/DOE and Sponsors 1954-2005.

** If all sponsors took this approach, DOE would have had no power, which is totally contrary to the original and primary purpose of EEInc.

*** Demand charges shown simply reflect 40% of Joppa Plant's demand/fixed costs for the years 1954-2005. Had the Joppa Plant been rate based utilizing a more traditional capital structure, the fixed costs would have been higher than shown.

Summary of Sales: Demand/Energy Split ($)

1954 - 2005

Year	Total EEInc Sales to all Parties			Sales to DOE					
	Demand	Energy	Total	Demand	Energy	Total	% Total Demand	% Total Energy	% Total Costs
1954	$6,880,993	$8,093,348	$14,974,341	$6,072,610	$7,502,458	$13,575,068	88.3%	92.7%	90.7%
1955	$12,714,523	$11,964,215	$24,678,738	$10,230,633	$9,769,482	$20,000,115	80.5%	81.7%	81.0%
1956	$15,385,406	$13,677,618	$29,063,024	$12,778,466	$11,680,532	$24,458,998	83.1%	85.4%	84.2%
1957	$15,246,303	$14,485,192	$29,731,495	$12,474,244	$11,865,275	$24,339,519	81.8%	81.9%	81.9%
1958	$15,541,024	$14,283,417	$29,824,441	$13,006,391	$11,741,363	$24,747,754	83.7%	82.2%	83.0%
1959	$15,697,082	$14,869,003	$30,566,085	$13,040,679	$11,862,536	$24,903,215	83.1%	79.7%	81.4%
1960	$16,020,746	$14,512,793	$30,533,539	$13,387,262	$11,775,971	$25,163,233	83.6%	81.1%	82.4%
1961	$15,978,207	$14,620,207	$30,598,414	$13,261,688	$11,689,237	$24,950,925	83.0%	80.0%	81.5%
1962	$16,265,258	$14,841,581	$31,106,839	$13,348,706	$11,502,360	$24,851,066	82.1%	77.5%	79.9%
1963	$15,994,798	$14,774,398	$30,769,196	$13,174,288	$11,377,419	$24,551,707	82.4%	77.0%	79.8%
1964	$16,601,813	$14,532,354	$31,134,167	$12,157,493	$10,016,464	$22,173,957	73.2%	68.9%	71.2%
1965	$16,561,642	$14,134,217	$30,695,859	$10,620,660	$8,479,569	$19,100,229	64.1%	60.0%	62.2%
1966	$17,213,190	$14,505,573	$31,718,763	$7,712,190	$5,985,149	$13,697,339	44.8%	41.3%	43.2%
1967	$16,998,641	$15,236,793	$32,235,434	$4,808,665	$3,817,496	$8,626,161	28.3%	25.1%	26.8%
1968	$17,441,964	$14,943,442	$32,385,406	$5,013,649	$3,924,300	$8,937,949	28.7%	26.3%	27.6%
1969	$16,910,933	$17,040,190	$33,951,123	$4,869,378	$4,344,152	$9,213,530	28.8%	25.5%	27.1%
1970	$17,972,902	$18,966,911	$36,939,813	$6,359,635	$7,115,323	$13,474,958	35.4%	37.5%	36.5%
1971	$21,403,578	$20,805,697	$42,209,275	$12,861,168	$14,533,283	$27,394,451	60.1%	69.9%	64.9%
1972	$24,877,269	$24,743,225	$49,620,494	$15,377,727	$17,670,487	$33,048,214	61.8%	71.4%	66.6%
1973	$24,119,612	$29,067,426	$53,187,038	$14,547,437	$19,178,097	$33,725,534	60.3%	66.0%	63.4%
1974	$26,826,055	$43,904,414	$70,730,469	$16,902,809	$30,308,786	$47,211,595	63.0%	69.0%	66.7%
1975	$26,848,466	$64,370,002	$91,218,468	$16,648,746	$45,793,821	$62,442,567	62.0%	71.1%	68.5%
1976	$27,526,466	$65,930,250	$93,456,716	$17,562,926	$43,512,833	$61,075,759	63.8%	66.0%	65.4%
1977	$28,833,142	$76,886,723	$105,719,865	$19,093,762	$49,325,858	$68,419,620	66.2%	64.2%	64.7%
1978	$29,979,567	$74,908,842	$104,888,409	$25,115,596	$60,315,967	$85,431,563	83.8%	80.5%	81.4%
1979	$29,520,292	$91,064,775	$120,585,067	$17,722,094	$58,250,730	$75,972,824	60.0%	64.0%	63.0%
1980	$25,074,964	$87,577,422	$112,652,386	$14,471,853	$44,686,191	$59,158,044	57.7%	51.0%	52.5%
1981	$24,975,354	$87,653,483	$112,628,837	$12,648,457	$29,437,129	$42,085,586	50.6%	33.6%	37.4%
1982	$22,756,839	$87,112,889	$109,869,728	$5,783,617	$7,237,329	$13,020,946	25.4%	8.3%	11.9%
1983	$22,287,992	$92,539,343	$114,827,335	$7,679,570	$36,482,949	$44,162,519	34.5%	39.4%	38.5%
1984	$38,060,865	$116,877,711	$154,938,576	$30,258,101	$102,297,490	$132,555,591	83.9%	86.1%	85.6%
1985	$35,230,535	$112,401,810	$147,632,345	$30,334,155	$104,550,497	$134,884,652	86.1%	93.0%	91.4%
1986	$31,323,043	$97,131,066	$128,454,109	$26,962,279	$92,361,431	$119,323,710	86.1%	95.1%	92.9%
1987	$28,448,992	$82,665,508	$111,114,499	$23,710,205	$73,288,237	$96,998,441	83.3%	88.7%	87.3%
1988	$43,422,720	$80,703,828	$124,126,548	$31,727,271	$69,880,760	$101,608,031	73.1%	86.6%	81.9%
1989	$44,829,740	$95,977,047	$140,806,787	$31,602,572	$82,985,402	$114,587,974	70.5%	86.5%	81.4%
1990	$51,296,816	$90,027,341	$141,324,157	$38,703,582	$74,155,025	$112,858,607	75.5%	82.4%	79.9%
1991	$56,369,165	$83,936,235	$140,305,400	$41,784,783	$70,211,872	$111,996,655	74.1%	83.6%	79.8%
1992	$57,950,225	$86,656,614	$144,606,839	$42,996,413	$71,383,388	$114,379,801	74.2%	82.4%	79.1%
1993	$85,306,116	$81,061,844	$166,367,960	$63,813,344	$62,899,283	$126,712,627	74.8%	77.6%	76.2%
1994	$79,186,131	$79,056,745	$158,242,875	$46,793,831	$48,713,821	$95,507,651	59.1%	61.6%	60.4%
1995	$81,722,090	$78,085,569	$159,807,659	$48,289,054	$47,447,974	$95,737,028	59.1%	60.8%	59.9%
1996	$78,627,670	$78,991,856	$157,619,525	$45,811,504	$47,651,258	$93,462,761	58.3%	60.3%	59.3%
1997	$77,538,970	$78,459,339	$155,998,309	$45,164,714	$46,740,554	$91,905,268	58.2%	59.6%	58.9%
1998	$74,578,419	$72,220,777	$146,799,196	$44,698,158	$43,026,824	$87,724,982	59.9%	59.6%	59.8%
1999	$72,386,230	$75,944,998	$148,331,228	$35,700,788	$37,006,515	$72,707,303	49.3%	48.7%	49.0%
2000	$78,134,681	$76,231,646	$154,366,327	$31,025,637	$26,870,291	$57,895,928	39.7%	35.2%	37.5%
2001	$82,740,096	$76,839,172	$159,579,268	$23,920,889	$21,702,070	$45,622,959	28.9%	28.2%	28.6%
2002	$86,100,349	$79,648,370	$165,748,719	$16,524,644	$14,991,726	$31,516,370	19.2%	18.8%	19.0%
2003	$73,747,333	$83,875,323	$157,622,656	$7,189,225	$8,792,182	$15,981,407	9.7%	10.5%	10.1%
2004	$70,227,989	$88,198,436	$158,426,425	$330,265	$233,176	$563,441	0.5%	0.3%	0.4%
2005	$76,451,266	$88,161,242	$164,612,509	$744,628	$87,386	$832,015	1.0%	0.1%	0.5%
Total	$2,002,134,462	$2,977,218,219	$4,979,352,681	$1,076,818,441	$1,758,459,707	$2,835,278,148	53.8%	59.1%	56.9%
1954-79	$505,359,871	$737,182,607	$1,242,542,478	$328,148,901	$493,338,949	$821,487,850	64.9%	66.9%	66.1%
1987-2005	$1,299,064,999	$1,556,741,888	$2,855,806,887	$620,531,508	$848,067,742	$1,468,599,249	47.8%	54.5%	51.4%

Year	Sales to UE					
	Demand	Energy	Total	% Total Demand	% Total Energy	% Total Costs
1954	$323,353	$236,356	$559,709	4.7%	2.9%	3.7%
1955	$993,556	$893,231	$1,886,787	7.8%	7.5%	7.6%
1956	$1,042,776	$789,835	$1,832,611	6.8%	5.8%	6.3%
1957	$1,108,824	$1,078,717	$2,187,541	7.3%	7.4%	7.4%
1958	$1,013,853	$1,022,295	$2,036,148	6.5%	7.2%	6.8%
1959	$1,062,561	$1,252,904	$2,315,465	6.8%	8.4%	7.6%
1960	$1,053,393	$1,167,075	$2,220,468	6.6%	8.0%	7.3%
1961	$1,086,608	$1,197,696	$2,284,304	6.8%	8.2%	7.5%
1962	$1,166,621	$1,353,538	$2,520,159	7.2%	9.1%	8.1%
1963	$1,128,204	$1,411,330	$2,539,534	7.1%	9.6%	8.3%
1964	$1,777,728	$1,918,374	$3,696,102	10.7%	13.2%	11.9%
1965	$2,376,393	$2,378,344	$4,754,737	14.3%	16.8%	15.5%
1966	$3,800,400	$3,464,224	$7,264,624	22.1%	23.9%	22.9%
1967	$4,875,991	$4,882,769	$9,758,760	28.7%	32.0%	30.3%
1968	$4,971,326	$4,539,720	$9,511,046	28.5%	30.4%	29.4%
1969	$4,816,622	$5,180,837	$9,997,459	28.5%	30.4%	29.4%
1970	$4,708,355	$4,723,830	$9,432,185	26.2%	24.9%	25.5%
1971	$3,958,355	$3,083,113	$7,041,468	18.5%	14.8%	16.7%
1972	$4,389,544	$3,276,688	$7,666,232	17.6%	13.2%	15.4%
1973	$4,389,454	$3,978,136	$8,367,590	18.2%	13.7%	15.7%
1974	$3,905,899	$5,341,106	$9,247,005	14.6%	12.2%	13.1%
1975	$4,079,888	$6,366,057	$10,445,945	15.2%	9.9%	11.5%
1976	$3,985,416	$8,375,314	$12,360,730	14.5%	12.7%	13.2%
1977	$3,895,752	$9,543,300	$13,439,052	13.5%	12.4%	12.7%
1978	$1,945,589	$4,654,336	$6,599,925	6.5%	6.2%	6.3%
1979	$8,986,370	$22,002,479	$30,988,849	30.4%	24.2%	25.7%
1980	$8,081,488	$27,839,316	$35,920,804	32.2%	31.8%	31.9%
1981	$6,610,915	$22,633,739	$29,244,654	26.5%	25.8%	26.0%
1982	$6,593,020	$21,320,129	$27,913,149	29.0%	24.5%	25.4%
1983	$5,704,064	$16,227,182	$21,931,246	25.6%	17.5%	19.1%
1984	$2,537,879	$6,395,515	$8,933,394	7.0%	5.4%	5.8%
1985	$1,957,754	$1,476,182	$3,433,936	5.6%	1.3%	2.3%
1986	$1,742,960	$866,736	$2,609,696	5.6%	0.9%	2.0%
1987	$1,856,765	$1,427,194	$3,283,959	6.5%	1.7%	3.0%
1988	$4,657,328	$3,341,679	$7,999,007	10.7%	4.1%	6.4%
1989	$5,550,168	$4,053,467	$9,603,635	12.4%	4.2%	6.8%
1990	$5,089,886	$5,946,057	$11,035,943	9.9%	6.6%	7.8%
1991	$6,012,628	$5,789,327	$11,801,955	10.7%	6.9%	8.4%
1992	$6,040,467	$6,221,181	$12,261,648	10.4%	7.2%	8.5%
1993	$10,690,531	$7,696,417	$18,386,948	12.5%	9.5%	11.1%
1994	$8,257,263	$7,468,098	$15,725,361	10.4%	9.4%	9.9%
1995	$8,183,072	$7,732,848	$15,915,920	10.0%	9.9%	10.0%
1996	$8,128,020	$7,778,750	$15,906,770	10.3%	9.8%	10.1%
1997	$7,898,921	$8,036,368	$15,935,289	10.2%	10.2%	10.2%
1998	$7,900,225	8,645,384	$16,545,609	10.6%	12.0%	11.3%
1999	$10,611,448	11,780,109	$22,391,557	14.7%	15.5%	15.1%
2000	$15,564,540	16,820,728	$32,385,268	19.9%	22.1%	21.0%
2001	$21,635,742	19,632,987	$41,268,729	26.1%	25.6%	25.9%
2002	$26,303,008	24,403,728	$50,706,736	30.5%	30.6%	30.6%
2003	$27,374,919	30,375,491	$57,750,410	37.1%	36.2%	36.6%
2004	$30,200,475	37,617,742	$67,818,217	43.0%	42.7%	42.8%
2005	$29,718,143	34,945,588	$64,663,731	38.9%	39.6%	39.3%
Total	$351,744,460	$450,583,546	$802,328,006	17.6%	15.1%	16.1%
1954-79	$76,842,831	$104,111,604	$180,954,435	15.2%	14.1%	14.6%
1987-2005	$241,673,549	$249,713,143	$491,386,692	18.6%	16.0%	17.2%

NOTES: - Source: EEInc, UE, CIPS FERC Form 1.
- 1954-79 represents the initial 25-year contract period.
- 1987-2005 represents 18-year contract period covered by Mod 12 - Mod 15.

Schedule MLM-3

SCHEDULE MLM-4

HAS BEEN DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	)))))	Case No. ER-2007-0002

AFFIDAVIT OF MICHAEL L. MOEHN

STATE OF MISSOURI)
) **ss**
CITY OF ST. LOUIS)

Michael L. Moehn, being first duly sworn on his oath, states:

1. My name is Michael L. Moehn. I work in St. Louis, Missouri and I am employed by Ameren Services Company as Vice President of Corporate Planning.

2. Attached hereto and made a part hereof for all purposes is my Surrebuttal Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 36 pages and Schedules MLM-2, MLM-3 and MLM-4, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Michael L. Moehn

Subscribed and sworn to before me this 27th day of February, 2007.

Carolyn J. Woodstock
Notary Public

My commission expires: May 19, 2008

CAROLYN J. WOODSTOCK
Notary Public - Notary Seal
STATE OF MISSOURI
Franklin County
My Commission Expires: May 19, 2008