STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

CENTRAL ILLINOIS LIGHT COMPANY d/b/a AmerenCILCO, Proposed general increase in rates for delivery service.	)))))	Docket No. 06-0070
CENTRAL ILLINOIS PUBLIC SERVICE COMPANY d/b/a AmerenCIPS, Proposed general increase in rates for delivery service.	)))))	Docket No. 06-0071
ILLINOIS POWER COMPANY d/b/a AmerenIP, Proposed general increase in rates for delivery service.	))))	Docket No. 06-0072 (consol.)

DRAFT ORDER OF THE AMEREN COMPANIES

September 26, 2006

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I. INTRODUCTION

On December 27, 2005, Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP (collectively, the "Ameren Companies" or the "Companies") filed with the Illinois Commerce Commission ("ICC" or "Commission"), pursuant to Section 9-201 of the Public Utilities Act ("the Act") revised tariff sheets.

AmerenCILCO filed the following tariff sheets: 1st Revised Title Sheet; 1st Revised Sheet No. 1; Original Sheet No. 1.001; 1st Revised Sheet No. 2; Original Sheet No. 2.001; 1st Revised Sheet No. 3, Original Sheet No. 3.001; Original Sheet No. 3.002; Original Sheet No. 3.003; Original Sheet No. 3.004; Original Sheet No. 3.005; Original Sheet No. 3.006; Original Sheet No. 3.007; Original Sheet No. 3.008; Original Sheet No. 3.009; Original Sheet No. 3.010; Original Sheet No. 3.011; Original Sheet No. 3.012; Original Sheet No. 3.013; Original Sheet No. 3.014; Original Sheet No. 3.015; Original Sheet No. 3.016; Original Sheet No. 3.017; Original Sheet No. 3.018; Original Sheet No. 3.019; Original Sheet No. 3.020; Original Sheet No. 3.021; Original Sheet No. 3.022; Original Sheet No. 3.023; Original Sheet No. 3.024; Original Sheet No. 3.025; Original Sheet No. 3.026; Original Sheet No. 3.027; Original Sheet No. 3.028; Original Sheet No. 3.029; Original Sheet No. 3.030; Original Sheet No. 3.031; Original Sheet No. 3.032; Original Sheet No. 3.033; Original Sheet No. 3.034; Original Sheet No. 3.035; Original Sheet No. 3.036; 1st Revised Sheet No. 4, Original Sheet No. 4.001; Original Sheet No. 4.002; Original Sheet No. 4.003; Original Sheet No. 4.004; Original Sheet No. 4.005; Original Sheet No. 4.006; Original Sheet No. 4.007; Original Sheet No. 4.008 Original Sheet No. 4.009; Original Sheet No. 4.010; Original Sheet No. 4.011; Original Sheet No. 4.012; Original Sheet No. 4.013; Original Sheet No. 4.014; Original Sheet No. 4.015; Original Sheet No. 4.016; Original Sheet No. 4.017; Original Sheet No. 4.018; Original Sheet

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AmerenCIPS filed the following tariffs sheets: 1st Revised Title Sheet, 1st Revised Sheet No. 1; Original Sheet No. 1.001; 1st Revised Sheet No. 2; Original Sheet No. 2.001; Original Sheet No. 2.002; Original Sheet No. 2.003; Original Sheet No. 2.004; Original Sheet No. 2.005; Original Sheet No. 2.006; Original Sheet No. 2.007; 1st Revised Sheet No. 3; Original Sheet No. 3.001; Original Sheet No. 3.002; Original Sheet No. 3.003; Original Sheet No. 3.004; Original Sheet No. 3.005; Original Sheet No. 3.006; Original Sheet No. 3.007; Original Sheet No. 3.008; Original Sheet No. 3.009; Original Sheet No. 3.010; Original Sheet No. 3.011; Original Sheet No. 3.012; Original Sheet No. 3.013; Sheet No. 3.014; Original Sheet No. 3.015; Original Sheet No. 3.016; Original Sheet No. 3.017; Original Sheet No. 3.018; Original Sheet No. 3.019; Original Sheet No. 3.020; Original Sheet No. 3.021; Original Sheet No. 3.022; Original Sheet No. 3.023; Original Sheet No. 3.024; Original Sheet No. 3.025; Original Sheet No. 3.026; Original Sheet No. 3.027; Original Sheet No. 3.028; Original Sheet No. 3.029; Original Sheet No. 3.030; Original Sheet No. 3.031; Original Sheet No. 3.032; Original Sheet No. 3.033; Original Sheet No. 3.034; Original Sheet No. 3.035; Original Sheet No. 3.036; 1st Revised Sheet No. 4; Original Sheet No. 4.001; Original Sheet No. 4.002; Original Sheet No. 4.003; Original Sheet No. 4.004; Original Sheet No. 4.005; Original Sheet No. 4.006; Original Sheet No. 4.007;

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AmerenIP filed the following tariff sheets: 1st Revised Title Sheet; 1st Revised Sheet No. 1; Original Sheet No. 1.001; 1st Revised Sheet No. 2; Original Sheet No. 2.001; Original Sheet No. 2.002; 1st Revised Sheet No. 3; Original Sheet No. 3.001; Original Sheet No. 3.002; Original Sheet No. 3.003; Original Sheet No. 3.004; Original Sheet No. 3.005; Original Sheet No. 3.006; Original Sheet No. 3.007; Original Sheet No. 3.008; Original Sheet No. 3.009; Original Sheet No. 3.010; Original Sheet No. 3.011; Original Sheet No. 3.012; Original Sheet No. 3.013; Original Sheet No. 3.014; Original Sheet No. 3.015; Original Sheet No. 3.016; Original Sheet No. 3.017; Original Sheet No. 3.018; Original Sheet No. 3.019; Original Sheet No. 3.020; Original Sheet No. 3.021; Original Sheet No. 3.022; Original Sheet No. 3.023; Original Sheet No. 3.024; Original Sheet No. 3.025; Original Sheet No. 3.026; Original Sheet No. 3.027;

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Notice of the proposed tariff changes reflected in this rate filing was posted in the Ameren Companies' business offices and published in secular newspapers of general circulation in the Ameren Companies' service areas, as evidenced by publisher's certificates, in accordance with the requirements of 220 ILCS 5/9-201(a) and 83 Ill. Admin. Code Part 255.

On January 25, 2006, the Commission entered Suspension Orders commencing the instant investigation of the Ameren Companies' proposed general increase in rates in three separate dockets, and suspending operation of the proposed tariffs. On February 27, 2006, the Administrative Law Judges ("ALJs") entered a ruling consolidating the three dockets. On May May 17, 2006, the Commission entered a Re-suspension Order in the consolidated proceeding extending the suspension to and including November 25, 2006. The ALJs established a schedule for the submission of pre-filed testimony, hearings and briefs.

The following parties filed Petitions to Intervene, which were granted: Dynegy, Inc. ("Dynegy"); Local Unions 51, 309, 649, 702 and 1306 of the International Brotherhood of Electrical Workers, AFL-CIO ("IBEW"); Citizens Utility Board ("CUB"); BlueStar Energy Services, Inc.; Illinois Industrial Energy Consumers ("IIEC"); People of the State of Illinois ("AG"); Kroger Co. ("Kroger"); University of Illinois; MidAmerican Energy Company; Constellation NewEnergy, Inc., and Peoples Energy Services Corporation ("CNE/PES"); Wal-Mart Stores, Inc. ("Wal-Mart"); City of Champaign and the City of Urbana; Town of Normal; City of Bloomington; and Champaign County ("Cities").

Pursuant to notice as required by law and the Commission's rules, evidentiary hearings were held before duly authorized Administrative Law Judges (ALJs) on July 24-27, 2006, at the office of the Commission in Springfield, Illinois.

The following witnesses testified on behalf of the Ameren Companies: Scott A. Cisel, President and Chief Operating Officer of the Ameren Companies; Martin J. Lyons, Jr., Vice President and Controller of Ameren Corporation, Ameren CILCO, AmerenCIPS, and AmerenIP; Kathleen C. McShane, Senior Vice President, Foster Associates, Inc.; Lee R. Nickloy, Director – Corporate Finance and Assistant Treasurer, Ameren Corporation; Michael G. O'Bryan, Senior Capital Markets Specialist in Treasury – Corporate Finance, Ameren Services Company; Ronald D. Stafford, Managing Supervisor of Regulatory Accounting, Ameren Services Company; Michael J. Adams, Director, Energy, Navigant Consulting, Inc.; Wilbon L. Cooper, Manager – Rate Engineering and Analysis – Regulatory Policy and Planning, Ameren Services Company; Philip Difani, Jr., Consulting Engineer – Regulatory Policy and Planning, Ameren Services Company; Leonard M. Jones, Managing Supervisor – Restructured Services – Regulatory Policy and Planning, Ameren Services Company; C. Kenneth Vogl, Consultant, Towers Perrin; Robert Porter, Manager, Acquisitions, Ameren Services Company; Marla J. Langenhorst, Manager, Employee Benefits, Ameren Services Company; Krista Bauer, Managing Supervisor, Compensation and Performance, Ameren Services Company; Craig Boland, Supervising Engineer, Ameren Services Company; Ray Wiesehan, Manager - Safety and Resource Management, Ameren Services Company; Allen Clapp, President of Clapp Research Associates, P.C., Consulting Engineers and President of Clapp Research, Inc.; Keith Hock, Managing Supervisor, Transmission Services Business Center, Ameren Services Company; Paul Straughn, Manager of Development Energy Delivery, Ameren Services Company; Michael J. Getz, Managing Supervisor of Plant Accounting, Ameren Services Company; Richard Voytas, Manager of Corporate Analysis, Ameren Services Company; John B. Hollibaugh, Managing

Supervisor – AMR Implementation, Ameren Services Company; Jon R. Carls, Managing Supervisor – Regulatory Compliance, Ameren Services Company.

The following witnesses submitted testimony on behalf of Staff: Scott A. Struck Accountant, Accounting Department, Financial Analysis Division; Theresa Ebrey, Accountant, Accounting Department, Financial Analysis Division; Burma C. Jones, Accountant, Accounting Department, Financial Analysis Division; Janice Freetly, Senior Financial Analyst, Finance Department, Financial Analysis Division; Alan S. Pregozen, Manager, Finance Department, Financial Analysis Division; Peter Lazare Senior Economic Analyst, Rates Department, Financial Analysis Division, Cheri L. Harden, Rate Analyst, Rates Department, Financial Analysis Division; Mike Luth, Rate Analyst, Rates Department, Financial Analysis Division, Greg Rockrohr, Senior Electrical Engineer, Engineering Department, Energy Division; James D. Spencer, Senior Electrical Engineer, Engineering Department, Energy Division; Thomas L. Griffin, Accountant, Accounting Department, Financial Analysis Division; and Dr. Eric P. Schlaf Senior Economic Analyst, Energy Division.

The AG's witnesses were David J. Effron, consultant, and Scott J. Rubin, attorney and consultant.

The Cities' witness was Richard W. Cuthbert, Principal and Senior Economist, R.W. Beck, Inc..

CNE/PES's witnesses were Philip R. O'Connor, Ph.D., Vice President, Illinois Market, NewEnergy; Jennifer Witt, PES; and John L. Domagalski, Director of Pricing and Product Development, NewEnergy.

CUB's witnesses were Christopher C. Thomas, Director of Policy, and Edward Bodmer, consultant.

IBEW's witnesses were Matthew J. Moore, Business Representative, Local Union 51; Daniel F. Miller, Business Representative, Local Union 702; Tom Peterson, Business Representative, Local Union 51.

IIEC witnesses were Robert R. Stephens, Consultant, Brubaker & Associates, Inc.; Alan Chalfant, Consultant, Brubaker & Associates, Inc.; and Michael Gorman, Consultant, Energy Advisor, and Managing Principal, Brubaker & Associates, Inc..

Kroger's witness was Kevin C. Higgins, Principal, Energy Strategies, LLC.

Wal-Mart's witness was James T. Selecky, consultant, Brubaker & Associates, Inc..

On August 14, 2006, the ALJs marked the record "Heard and Taken."

II. RATE BASE

A. Summary of Uncontested/Settled Issues

The agreed or accepted adjustments to the Companies' proposed test year rate bases are as follows:

- the prudence and used and usefulness of certain plant; materials and supplies balances (Staff Ex. 9.0, pp. 3-4);
- Staff's proposed adjustment to Materials and Supplies Inventory (Staff Ex. 2.0, pp. 20-21; Resp. Ex. 16.0, p. 27);
- accumulated deferred income taxes ("ADIT") for pro forma plant additions (Resp. Ex. 16.11; Staff Ex. 13.0 (Corrected), p. 2)
- ADIT correction for AmerenCILCO (AG Ex. 1.0 CILCO; Staff Ex. 12.0, Sch. 12.03 (CIL), p. 2, col. (d); Resp. Ex. 16.1, Sch. 2, p. 2, col. (d));
- payroll withholding taxes (Staff Ex. 13.0 (Corrected), pp. 14-16; Tr. pp. 529-530);

- lead days for AmerenIP property tax payments and other O&M expenses (Resp. Ex. 37.0, p. 36);
- interest lead of AmerenIP TFTNs in the calculation of cash working capital;
- the reflection of Ameren Services Company ("AMS") plant (Staff Ex. 3.0, pp. 10-11; Resp. Ex. 16.0, p. 26).

B. Plant Additions

The Ameren Companies state that they provided ample support for costs related to plant additions, and should be allowed to recover those expenses in rates. These additions are real and tangible, and used and useful to ratepayers. Staff has not objected to any of the Ameren Companies' plant addition costs as being unreasonable or unnecessary. Instead, Staff's proposed disallowances are related solely to disputes over documentation of the Ameren Companies' reasonably incurred costs.

Staff proposed certain adjustments to the Ameren Companies' level of plant additions, based upon claims of inadequate documentation. (Staff Ex. 13.0, pp. 17-22) While Ms. Ebrey accepted some of the additional documentation provided in Company rebuttal, she did not accept various other documents as adequately supporting the underlying plant additions recorded on the books of the Ameren Companies.

Staff's rebuttal testimony contains certain errors with respect to disallowances for recovery of plant additions. (Resp. Ex. 36.0, pp. 36-41.) Specifically, in her rebuttal testimony, Ms. Ebrey (1) made certain mathematical errors in summing invoice costs and schedule presentation, (2) did not accept contractual documentation as adequate support for certain project costs, and (3) erroneously continued to apply her adjustment percentage to all gross plant additions without regard to whether such additions are in the Ameren Companies requested level of utility plant in service.

The Commission finds that the Ameren Companies have adequately supported the plant additions contested by the Staff and rejects the proposed adjustments.

C. Pro forma Plant Additions

Staff proposed disallowing a portion of the costs related to the project to integrate IP into Ameren's Customer Service System. At the time of filing, the Ameren Companies requested pro forma cost recovery for this project at an estimated $11.939 million. The Company explained that the actual costs for this project are over $12 million, and the underlying assets are used and useful in providing service to customers. (Resp. Ex. 16.0, p. 30; Ex. 16.13.) However, to limit the number of issues surrounding this project, the Ameren Companies agreed in rebuttal testimony to reduce cost recovery on this project to $12.131 million, the level of cost support previously provided to Staff during the field work audit on January 30, 2006.

The Ameren Companies stated that they provided sufficient justification and support for full recovery of the actual costs in the amount of $12.131 million. Staff has provided no reason why the Ameren Companies' cost detail for the project cannot be relied upon – in fact, Ms. Ebrey testified that she relied upon it herself in determining "unsupported costs." (Tr. at p. 552, lines13-22, p. 553, lines 1-8.)

The Commission agrees that the Ameren Companies have provided adequate support for the project and Staff's adjustment is rejected.

D. G&I Plant

A principal contested issue in this case involves the functionalization of general and intangible ("G&I") plant and associated expenses.

General plant consists of assets such as land, buildings and structures, office furniture and equipment, transportation equipment, stores equipment, tools, shop and garage equipment, laboratory equipment, power operated equipment and communication equipment. Each of these types of assets has a unique depreciable life which would be determined via a depreciation study.

Intangible plant consists primarily of software or systems that are purchased or developed for use by the Companies. For the most part, intangible plant is amortized over a short period of time (e.g., five years).

The Ameren Companies explained that historically, while some of the G&I plant assets were used by and benefitted more than one line of business, the assets primarily benefitted the "pipes and wires" businesses. For example, the land and structures that have been recorded as G&I plant represent discrete assets that can be identified and assigned or allocated to specific lines of business. The vast majority of the assets in those accounts are district field facilities that house field operations personnel and have never provided support to the electric production business. Accordingly, it would be inappropriate to assign or allocate a portion of these G&I plant assets to the electric production business.

Because G&I plant can have multiple uses, the Commission must "functionalize" that plant, i.e., it must determine what portion of the plant supports a particular function. The Commission recently again made clear that our preference is for the use of a "direct assignment" of costs, rather than the use of an allocator approach, such as the general labor expense allocator that we employed in the original DST rate cases. *Commonwealth Edison Co.*, Docket No. 05-0597, Order at p. 27 (July 26, 2006).

The Commission's decision to rely on direct assigment over the general labor allocator is a sound one. The labor allocator is easy to apply, but can produce anomolous results. The allocator uses labor expense to allocate const to different functions, by using a ratio, the denominator of which is the total labor expense and the numerator of which is the labor expense for a particular function. Tr. at 771 (Chalfant). The labor allocator does not take into consideration the nature or use of the assets. The approach is merely a mathematical calculation to allocate the costs of assets, in aggregate, to various lines of business. For example, a vehicle used exclusively by electric crews would be directly assigned to the electric business in the ASP. Using the labor allocator, a portion of the same truck would be allocated to each line of business (i.e., electric transmission, electric distribution, and gas).

The Ameren Companies provided a simple example to demonstrate how the labor allocator can produce unreasonable results. In the example, a company has both distribution and generation functions, with 10 employees who are paid equally. Five employees are in distribution and five are in generation. Thus, under the labor allocator, 50% of G&I plant would be allocated to distribution and 50% would be allocated to generation. Tr. 771-72 (Chalfant).

If that company were to make additional investment in software to make distribution more efficient, the allocator produces a result that is the opposite of what we would expect. If the company installs a new software system that allows to operate the distribution system with only four employees, less G&I plant is allocated to distribution, not more. Instead of 50% (5/10) of G&I plant being allocated to distribution, only 44% (4/9) is allocated to distribution. Tr. 771-74 (Chalfant). Thus, where the company invests more in software to assist distribution, the labor allocator assigns 5/9 of the new investment to generation, and alters the allocation of existing investment by assigning more of it to generation, irrespective of what use the generation function makes of the new software.

Accordingly, the Commission's clearly stated preference for direct assignment is proper and reflects sound regulatory policy.

The Ameren Companies explained that they functionalized G&I plant in a manner precisely consistent with the Commission's policy. Based on an exhaustive review and analysis, the Companies assigned plant where they could, and used appropriate allocators where they could not.

Mr. Adams oversaw an Asset Separation Project ("ASP"). The ASP represents the results of the review of the Company's continuing property records to determine which assets should be assigned or allocated to the electric distribution business. The objective of the ASP was to determine how each asset was used and to assign the cost of the asset to the appropriate line of business according to its use. Where possible, an asset was directly assigned to a particular line of business. If an asset supported more than one line of business, an allocator was employed to assign the cost of the asset to each line of business it supported.

The starting point for the study was a listing of each of the Company's assets. Resp. Ex. 7.0 CILCO, p. 4. Based upon a review of those assets, a preliminary determination was made as to whether the asset supported one or more lines of business. Direct assignment of assets was employed wherever possible. For example, electric production, transmission, and distribution plant, and gas plant were directly assigned to the appropriate business function. Some G&I plant assets were also directly assigned to particular lines of business. The remaining assets, which are recorded on the Company's books as either gas or electric G&I Plant, were reviewed since they may support more than one business function and thus require allocation among business units. *Id.*

To determine how the G&I Plant was actually used, information regarding the use of the asset was reviewed. If necessary, the users of the assets were contacted to determine which lines of business the assets support and an appropriate allocator to apply to the assets. Such employees are in the best position to have knowledge of how the assets are used and how best to allocate or assign the costs of such assets to the various lines of business. The appropriate allocators were then applied to the assets in order to assign or allocate the costs of each asset to a particular line of business. Resp. Ex. 7.0 CILCO, p. 5.

Direct assignment of G&I Plant was employed whenever possible. When direct assignment was not possible, the specific continuing property records for the particular asset were examined to determine if there was adequate information to determine a basis of allocation. If sufficient information was not available, users of the specific asset were contacted to determine the exact use of the asset and an appropriate allocation basis. Resp. Ex. 7.0 CILCO, pp. 5-6.

In most cases, the allocators are based on readily available information such as customer counts or operation and maintenance ("O&M") expense levels. For the more generalized allocators, such as number of customers or O&M expense levels, the information needed to calculate the allocation percentages was taken directly from the Company's 2004 FERC Form 1. To develop the more specialized allocators, the organizations responsible for managing the asset were contacted to obtain insights as to the appropriate allocation of costs to the individual lines of business. Resp. Ex. 7.0 CILCO, p. 6.

The Companies submitted detailed studies of the G&I plant and the appropriate allocation and assignment of the assets to the electric transmission, electric distribution, gas and the electric generation businesses reflected on the books of the regulated companies. The Companies' ASP, supported by detailed workpapers, shows on an account-by-account basis the assets which are included in the Companies' proposed rate base in these proceedings. The ASP shows the allocator used to assign the cost of the plant to the various lines of business reflected on the books of the regulated companies and the calculation of each allocator. Resp. Ex. 37.0, pp. 4-5.

Accordingly, the Ameren Companies' functionalization of G&I plant was sound, supported by an exhaustive and reasoned analysis and consistent with clearly stated Commission policy.

Both the Staff and IIEC proposed adjustments to G&I plant. Notably, neither party challenged any particular element of the Companies' study. Nor did they question the prudence or used and usefulness of any specific plant item wholly or partially included in rate base. Rather, their adjustments – while arrived at by different paths – were based on the Commission's Orders in each Company's last delivery service tariff ("DST") proceeding. As will be discussed, to adopt the position of Staff and IIEC, the Commission must conclude, despite all evidence to the contrary, either that: (i) the G&I plant assets on the utilities' books are being used by the Companies' affiliates' non-regulated generation businesses, or (ii) the assets are not being used in support of the Companies' regulated electric businesses. Neither of the propositions is correct.

The Staff challenged the Companies' G&I plant levels on two bases: first, the Staff contend that G&I plant should not be directly assigned, and second, the Staff alleged that the Companies were merely trying to refunctionalize to distribution that which the Commission allocated to generation in the DST cases.

The Staff has misunderstood the Commission's policy regarding functionalization of G&I plant. Staff witness Lazare contended that "The Commission has concluded that these costs are not conducive to a direct assignment approach and should be instead allocated on a general basis." The Commission has done no such thing. In the Order in Docket No. 01-0645, on which Mr. Lazare relied, the Commission "note[d] that while it has expressed a preference for the direct assignment of costs, that preference was subject to the condition that the costs in question are suited to direct assignment and sufficient cost data is available to make direct assignments." The Commission continued, "In the Commission's view, important considerations in assessing whether costs should be directly assigned to a specific function, or how they should be allocated among functions, are the nature of the facilities and the type and scope of activities for which they are used."

The costs at issue here are clearly capable of being directly assigned. Once the usage of the G&I plant assets is determined, the costs can be direct assigned to one or more of the lines of business. For example, if a bucket truck is used exclusively by the electric distribution business, the cost of the vehicle can be direct assigned to the electric distribution business. If the asset is used by both the electric transmission and the electric distribution business, but not the gas business, the cost can be directly assigned to the electric transmission and electric distribution businesses and allocated between the two businesses based upon its actual usage or a proxy for its usage. Resp. Ex. 37.0, p. 19.

If there were any doubt about this, the Commission's recent order in *Commonwealth Edison Co.* (Docket No. 05-05997) removed it:

> Further, the Commission agrees with ComEd that use of "direct assignment" of costs is the preferred approach over the general labor allocator approach. *Because determining such costs is possible*, the Commission is in agreement with ComEd that direct assignment should be used in this case. (emphasis added) (p. 27)

Staff's second basis for its adjustments is also baseless. In the DST cases, the Commission functionalized a certain amount of G&I plant to generation. Mr. Lazare claimed in this case that the "Companies are attempting to refunctionalize this plant back to the revenue requirement." This is simply incorrect. The Companies' ASP reflects the actual assets which were on the books as of December 31, 2004 and how such assets are used by the Companies to provide service to its customers. The G&I plant which has been included in the Companies' rate base in these proceedings reflect the plant that is used by the electric delivery services business. The Companies transferred the G&I plant which supported the non-regulated generation business to those businesses. Therefore, the Companies are not attempting to refunctionalize plant back to the electric distribution business but rather is accurately reflecting how the assets are used and attempting to earn a fair return on those assets which are used by the electric distribution business from the customers which benefit from the use of such assets.

Moreover, the Companies cannot refunctionalize to generation that which is no longer there. The amount that Staff proposes to disallow is seriously overstated. For example, since Mr. Lazare relied upon G&I plant in service as of December 31, 2000 for AmerenCILCO, his proposed disallowance would include plant which has already been transferred to the non-regulated generation company (i.e., ARG), which was formed in 2003. Similarly with AmerenCIPS, Staff witness Lazare employs information as of December 31, 1999 to quantify his proposed adjustment. The non-regulated generation company AGC, which consists primarily of AmerenCIPS' former generation facilities was formed in 2000 and the assets would have been transferred from the Company's books to AGC in 2000. Resp. Ex. 37.0, p. 21.

For both AmerenCILCO and AmerenCIPS, the G&I plant which was transferred to ARG and AGC would already have been removed from the Companies' proposed rate base in these proceedings. Therefore, Staff witness Lazare is proposing to disallow plant which is not even included in rate base. Resp. Ex. 37.0, p. 21.

IP's 2000 test year used in its last DST proceeding included significant amounts of intangible plant associated with information systems which were used by the Company. Since the acquisition of IP by Ameren, many of the systems on the books of IP have been written off by Ameren. Despite the fact that the intangible plant has been written off since AmerenIP's last DST proceeding and is not included in rate base in these proceedings, Staff is proposing to disallow a portion of the intangible plant that is no longer even on the books of the Company. Resp. Ex. 37.0, pp. 21-22.

Staff's's position also fails to recognize the further amortization or depreciation of the G&I plant assets which were on the books of the Companies as of December 31, 1999 or 2000. For example, most intangible plant has an amortized life of five years. Therefore, most if not all of the intangible plant which was on the Companies' books in the last DST proceedings would be fully amortized and have a net book value of zero in these proceedings. However, Staff proposes to disallow the value of the intangible plant that was on the books of the Companies in the prior DST proceedings, even though the assets have a net value of zero in rate base of these proceedings. Resp. Ex. 37.0, p. 22.

The same would also be true with general plant. Staff witness Lazare's proposed adjustment fails to reflect the further depreciation of general plant since the last DST proceedings. Resp. Ex. 37.0, p. 22.

The Ameren Companies stated that this is no mere tweaking of the numbers. For example, Mr. Lazare had proposed a disallowance of AmerenIP's G&I plant as of December 31, 2000 of $123,631,000.[1] Once the G&I plant as of December 31, 2000 which is no longer on the

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[1] Ibid, pp. 16-17, lines 377-380.

Company's books or via pro forma adjustments are removed, Staff's adjustment would be $12,037,000 instead of $123,631,000. Resp. Ex. 37.0, p. 24.

For IIEC, Mr. Chalfant's core contention is that all G&I plant is used for all functions – including functions undertaken by the generation affiliates. IIEC (and the Staff for that matter) would have the Commission believe that the Companies' commercial office buildings in Marion, Quincy, Lincoln, Decatur, Springfield or elsewhere throughout state are used by the non-regulated generation businesses. To the contrary, these facilities house crews which are responsible for operating and maintaining the pipes and wires businesses in these communities. These crews (and the assets that they use) do not spend portions of their time at the non-regulated generation businesses' facilities. They begin their days at the commercial offices. During the day, they are in the field constructing and maintaining the Companies' pipes and wires. At the end of the day, the crews return to the commercial office and store their equipment on the grounds overnight.

Mr. Chalfant did not propose to use the labor allocator in this case. Rather, he proposed that increases in G&I plant since the prior DST cases be limited to the percentage increases in distribution plant over the same period. The Ameren Companies stated that there are three reasons why this proposal should be rejected.

First, the test years used in the Companies' last DST proceedings are 4 to 5 years older than the test year in these proceedings. No party has challenged that calendar year 2004 is an appropriate test year for these proceedings, yet Mr. Chalfant seeks to bring outdated 4 to 5 year old data into this proceeding without regard to the applicability of the data. The Companies' operations have changed significantly over the last four years and it is not appropriate to set rates – directly or indirectly – on an outdated test year. Resp. Ex. 37.0, p. 6.

Second, there is no sound basis for this proportionality principle. Mr. Chalfant acknowledged at hearing that there is no relationship between investment in distribution assets and G&I plant. A utility need not buy a new software system when it builds a new line, and it need not build a new line when it buys a new software system.

Lastly, the Commission pointedly rejected this very proposal in the ComEd case last month:

> Moreover the Commission finds that the IIEC's argument for limiting the increase in general and intangible costs in proportion to distribution plant costs to be insufficient and unsupported by the record. Although the IIEC witness advocated such a position he never identified any cogent reason for such a correlation.

Commonwealth Edison Co., Docket No. 05-0597, p. 27 (July 26, 2006)

To adopt the position of either Staff or IIEC, the Commission must conclude that, despite the evidence to the contrary, that the G&I plant assets are being used by the non-regulated generation businesses or that the assets are not being used in support of the Companies' electric transmission, electric distribution, gas or electric generation businesses which remain on the books of the regulated companies. There is no evidence in the record to support either claim, because such positions are wrong and unsupportable. The G&I plant assets included in rate base in these proceedings are being used to provide electric distribution services to the Companies' customers.

Ameren acquired Illinois Power from Dynegy effective October 1, 2004. Only the "pipes and wires" businesses and the supporting assets were acquired by Ameren. Dynegy owns the former IP fossil generation and Exelon owns the former IP nuclear generation. Tr. 777 (Chalfant). For Staff's and IIEC's position to be accepted, the Commission must conclude that either:

(1) The G&I plant which was acquired by Ameren associated with the acquisition of Illinois Power's pipes and wires businesses continue to support a generation function which is owned by Dynegy; or

(2) The G&I plant which was acquired by Ameren associated with the acquisition of Illinois Power's pipes and wires businesses is not used to support AmerenIP's regulated electric businesses.

There is no evidence in the record to support either position simply because neither position is true. More to the point, neither Staff witness Lazare nor IIEC witness Chalfant identifies any specific G&I plant assets to disallow. Instead each merely developed a number and deemed that amount of G&I plant to be unrelated to the distribution business and thus unrecoverable. Resp. Ex. 37.0, pp. 7-8.

The Commission concludes that the adjustments to G&I plant and associated expenses proposed by the Staff and IIEC should be rejected. The proposed adjustments are unsupported by the evidence and inconsistent with the Commission's very clear preference for direct assignment of costs. The use of a general allocator is not preferred, and as shown in the foregoing discussion, can lead to illogical results.

E. Reallocation of Depreciation Reserve

The depreciation study conducted in preparation for this rate case indicates a substantial increase in depreciation rates for AmerenIP. The Ameren Companies explained that, in the interest of ratepayers, they have not recommended an increase in AmerenIP's depreciation rates at this time. However, the Ameren Companies are requesting permission to reallocate the AmerenIP depreciation reserve in order to mitigate the future impacts of changes in depreciation rates on customers. (Resp. Ex. 16, pp. 11-13; Resp. Ex. 36.0, pp. 15-17.) Resp. Exhibit 36.4 represents the proposed reallocation based on year-end 2004 reserve balances, along with an illustration of the depreciation rate impact of the reallocation.

The Ameren Companies' understanding is that they could request such approval from FERC. (*Id.*) However, since a depreciation study has been conducted in conjunction with the instant proceedings, the Ameren Companies consider it to be more administratively efficient and more appropriate to request such approval from the ICC at this time.

Staff contends that it has found nothing to indicate that reallocation of the depreciation reserve is acceptable under the rules of Generally Accepted Accounting Principles ("GAAP"). Ameren Companies' witness Stafford testified that applicable guidance is found in the Statement of Financial Accounting Standards 71:

> While there may be other authoritative sources that provide support under GAAP, the Statement of Financial Accounting Standards ("FAS") 71: Accounting for the Effects of Certain Types of Regulation does provide guidance that can be construed as supportive of the Ameren Companies' request, given that AmerenIP is a rate-regulated utility under ICC jurisdiction. Specifically, at paragraph 51 of FAS 71, a threshold issue is addressed: "Should accounting prescribed by regulatory authorities be considered in and of itself generally accepted for purposes of financial reporting by rate-regulated enterprises?" The answer provided in paragraph 52 stated in part "…..the economic effect of regulatory decisions-not the mere existence of regulation-is the pervasive factor that determines the application of generally

> accepted accounting principles." In other words, actions of a regulator, such as in this case approving reallocation of the depreciation reserve, can directly impact and influence whether a rate-regulated utility is in compliance with GAAP.

(Resp. Ex. 36.0, pp. 17-18.)

The review of AmerenIP's depreciation reserve by account and by function indicated a large disparity in the actual reserve vs. the calculated reserve conducted in preparation of the depreciation study. (*Id.* at 18.) As illustrated on Respondents' Exhibit 36.4, the reserve shortfall is predominantly in shorter-lived assets. Amortization of the reserve shortfall of shorter-lived assets occurs over a much shorter remaining life, and results in higher overall depreciation expense. (*Id.*) By reallocating the reserve, the customer impact of any reserve shortfalls on an account by account basis is mitigated. (*Id.*)

In this specific case, this reallocation of depreciation reserve has the impact of mitigating the otherwise necessary increase in depreciation expense by $17,099,000 annually, as shown on Respondents' Exhibit 36.4. (*Id.*) Because the record demonstrates that reallocation is reasonable and will be a significant benefit to AmerenIP's customers on a going-forward basis, the Commission approves this proposal.

F. OPEB Liability

1. Unfunded OPEB

AG witness David J. Effron and ICC Staff witness Burma Jones propose including accrued OPEB liability in rate base.

a. AG

The AG contends that ratepayers have supplied funds in excess of what the Ameren Companies have paid for OPEB, and that the excess is available to support the Company's operations. (AG Ex. 1.0, pp. 7-8.) The Ameren Companies explained, however, that pension and OPEB expenses approved in prior orders (in 1999 or 2000) were low compared to pension and OPEB expenses in the current test year, reflecting expenses for better funded plans that were generated by the high equity returns, higher interest rates, and lower medical costs during the late 1990s.

Such high equity returns did not happen in the 2000-02 period. This fact, combined with decreasing interest rates has led to a decline in the funded status of the Ameren Companies' pension and OPEB plans. The Ameren Companies explained that this decline in funding is consistent with the experience of other companies offering pension plans, during the same time period. In other words, the decrease in the plan's funded status is largely due to factors outside of the Ameren Companies' management control.

According to the Ameren Companies, on average, over each of the past several years AmerenCIPS has spent \$5.2 million more on OPEB expenses than they have received in rates (\$6.0 million average annual contribution less \$0.8 million received annually in rates). AmerenCILCO has annually spent \$1.4 million more than they have received in rates, and AmerenIP has annually spent \$4.6 million more than they have received in rates. (Resp. Ex. 42.0, p. 4.) Thus, there is no excess, and the AG's proposed adjustment is rejected.

On these grounds, Mr. Vogl testified that if an adjustment to rate base were to be made, he would recommend that the correct adjustment would be an increase to rate base equal to the excess of OPEB funds contributed over the amount collected in rates from ratepayers. (Resp. Ex. 21.0, pp. 8-9.)

b. ICC Staff

Staff argued that accrued OPEB liability is a "cost-free source of capital on which shareholders are not entitled to receive a return." Ameren witness Vogl explained that a cost-free source of capital on which shareholders are entitled to receive a return would represent funds collected through rates that are attributable to OPEB benefits, but ultimately not used to pay for OPEB benefits. (Resp. Ex. 42.0, pp. 2-3.) But this is not what the accrued OPEB liability represents. As mentioned above, the accrued OPEB liability represents the excess of OPEB expense recorded by the Company (a non-cash expense recorded by the Company on its income statement) over the amounts the Company has actually paid for OPEB. The only way that Staff's description could be accurate would be if the OPEB expense recorded by the Company were equal to the funds collected in rates attributable to OPEB benefits for every year.

The Ameren Companies stated that this is clearly not the case. The OPEB amount collected through rates is fixed for a period of time. The amount of OPEB expense recorded by the Company, however, varies from year to year and has generally increased over the past several years. Thus, to the extent the OPEB expense recorded by the Company differs from the amount collected through rates, the accrued OPEB liability gets farther and farther away from what Staff describes as a "cost-free source of capital on which shareholders are not entitled to a receive a return." Thus, Staff's adjustment is rejected as well.

2. ADIT Treatment

Staff and AG have also recommended an adjustment to OPEB-related Accumulated Deferred Income Taxes ("ADIT") in the calculation of pro forma rate base. (AG Ex. 1.0, pp. 7-8; ICC Staff Ex. 14.0, pp. 19-20.) The Ameren Companies acknowledge that their direct testimony included, in error, OPEB-related ADIT in their rate base calculations. In rebuttal testimony, Mr. Stafford agreed with Mr. Effron's recommendation to treat OPEB-related ADIT consistently with the Companies' treatment of accrued OPEB liability, and thus removed OPEB-related ADIT from rate base. Thus, OPEB-related ADIT should be removed from rate base. (Resp. Ex. 36.0, pp. 32-33.)

G. Cash Working Capital

Cash working capital is the amount of funds required to finance the day-to-day operations of the Company. Cash working capital determinations are generally intertwined with lead-lag studies that are used to analyze the lag time between the date customers receive service and the date that customers' payments are available to the Company. This lag is offset by a lead time during which the Company receives goods and services, but pays for them at a later date. The "lead" and "lag" are both measured in days. Since the test year was a leap year, the dollar-weighted lead and lag days are then divided by 366 to determine a daily cash working capital factor ("CWC factor"). This CWC factor is then multiplied by the annual test year cash expenses to determine the amount of cash working capital required for operations. The resulting amount of cash working capital is then included as part of the Company's rate base. The test year operating expenses to which the leads and lags were applied are described in the direct testimony of Company witness Stafford.

Two broad categories of leads and lags should be considered: 1) lags associated with the collection of revenues owed to the Company ("revenue lags"); and 2) lead times associated with the payments for goods and services received by the Company ("expense leads"). A revenue lag refers to the elapsed time between the delivery of the Company's product (i.e., electricity) and its ability to use the funds received as payment for the delivery of the product. The expense lead refers to the elapsed time from when a good or service is provided to the Company to the point in time when the Company pays for the good or service and the funds are no longer available to the Company.

Navigant Consulting, Inc. ("NCI") performed a lead-lag study by analyzing each Company's cash transactions and invoices for the twelve months ended December 31, 2004. Based on that study (with certain adjustments accepted during the case) the Ameren Companies have proposed cash working capital requirements of $754,000 for AmerenCILCO; $1.006 million for AmerenCIPS; and $285,000 for AmerenIP. Ameren Exs. 37.0, p. 50; 36.1; 36.2; 36.3. In contrast, Staff has proposed cash working capital requirements of ($1,575,000) for AmerenCILCO, ($3,470,000) for AmerenCIPS, and ($6,613,000) for AmerenIP. Staff's negative results arise for its differences with the Companies in five specific areas.

1. Lead/lag methodology

The principal difference between Staff and the Companies relates to the overall methodology used. The Companies employed a "Net Lag" methodology to determine its cash working capital requirements. Under the Net Lag approach employed by the Companies, an overall revenue lag, representing the passage of time from when the Companies provide service to its customers and the receipt of available funds from its customers for such services, is netted against the expense lead for the various expense classifications. The net of the revenue lag and expense lead are then multiplied by the expense level for each expense classification. Resp. Ex. 16.0, p. 26.

In this proceeding, Staff proposed to use a "Gross Lag" methodology to calculate the Companies' cash working capital requirements. Under the Gross Lag methodology, the revenue lag is applied to gross revenues and non-cash items which are used to reduce the revenues. The expense leads are applied to each expense classification. Resp. Ex. 16.0, p. 26.

Thus, the primary difference between the two methodologies is the reflection of revenues in the Gross Lag methodology.

The Commission has endorsed both methods in the past. The methodology employed by the Companies is consistent with the methodology ultimately approved by the Commission in Docket Nos. 02-0798/03-0008/03-0009 (Cons.), the prior gas rate cases of AmerenCIPS and

AmerenUE-Illinois. In that case, the Staff endorsed the Net Leg approach. Resp. Ex. 16.0, p. 26. In this case, hwoever, the Staff has endorsed the gross lag approach.

The Ameren Companies stated that there are three reasons why they adopted the Net Lag methodology to determine its CWC requirements. First, the Companies wanted to ensure consistency across all of the companies. Second, the methodology has been accepted by both state regulatory jurisdictions in which the companies operate. Finally, most state regulatory jurisdictions have adopted the Net Lag approach to determine a company's CWC requirements. Resp. Ex. 16.0, p. 30.

The Ameren Companies also stated that the ability to adopt one methodology for both jurisdictions is expected to reduce the Company's cost of conducting such analyses. In addition, the iterative nature of the Gross Lag methodology increases the difficulty of calculating the Companies' CWC requirements. The Gross Lag CWC calculation requires modification each time any one of the following components is changed:

1. Revenues
2. Proposed increase
3. Uncollectible expenses
4. Depreciation and Amortization Expenses
5. Return on equity
6. Non-cash OPEB expenses.

The Net Lag methodology does not include revenues (except to calculate the revenue lag), so no such adjustments are necessary. The Companies' studies do not include uncollectible expenses, depreciation and amortization, return on equity or non-cash OPEB expenses, therefore, no adjustment to the Companies' methodology is required.

The Commission finds that the Companies have appropriately prepared, documented and supported its cash working capital analysis. The Net Lag methodology used by the Companies has been accepted by this Commission in prior rate proceedings. No other party to this proceeding has expressed concerns with the use of the Net Lag methodology. Accordingly, the use of the Net Lag approach is approved. The Commission does not by this action suggest that the Gross Lag approach is inappropriate for use in Illinois.

2. Interest Expense LED

Staff proposes to use 366 days in the year as the basis for calculating the expense lead time on interest expense. According to Staff, this approach would be "consistent with the Companies' calculations."[2] The impact is to reduce the cash working capital requirements of AmerenCILCO, AmerenCIPS, and AmerenIP by $4,800, $8,500, and $25,000 respectively.

The Ameren Companies explained that, where applicable, and consistent with standard industry practice, they use 365 days in their calculations of revenue lags and expense leads. Recognizing, however, that the Companies' test year was a leap year, the Companies used 366 days in the denominator when calculating a daily measure of cash working capital requirements for each expense item considered in the Companies' lead lag study (i.e., the cash working capital factor which is defined as the net lag divided by the number of days in the test year). This daily measure was then multiplied by test year expenses at proposed rates to derive the cash working capital requirements of the Companies. Thus, Staff is not being "consistent with the Companies' calculations." Resp. Ex. 37.0, p. 47.

Moreover, according to Ameren, Staff's position itself seems to be internally inconsistent and thus warrants rejection by the Commission. Throughout the lead lag study, the midpoint of a

[2] Staff Exhibit 13.0, page 10, line 186.

period is determined by dividing 365 days by the appropriate period of time. For example, to determine the midpoint of a year, the study would divide 365 by 2 to arrive at the midpoint of the year, or 182.5 days. Resp. Ex. 37.0, pp. 47-48.

When determining the midpoint of a year for purposes of determining the interest expense lead, Ms. Ebrey uses 366 days to arrive at a midpoint of 91.50 days. The variance in the calculations yields a difference of 0.25 days. While the use of the difference seems small, the impact on the Companies' cash working capital requirement ranges from approximately $5,000 to $25,000. Resp. Ex. 37.0, pp. 47-48.

The Ameren Companies' approach appears reasonable and supported by the record Accordingly, it is hereby approved.

3. Capitalization of Payroll in CWC Requirements

Staff proposes to include the capitalized portion of payroll expense in the cash working capital requirements of the Companies. The Ameren Companies stated that this is inappropriate because the capitalized portion of payroll would already be included in rate base and, if approved by the Commission, would earn a return. Second, without analyzing the payroll portion of all capital projects, it is impossible to determine whether such projects accrued an allowance for funds used during construction, which is effectively a carrying cost that is included in the overall capitalized cost. Third, Ms. Ebrey is proposing to select the capital costs associated with only one lead lag item for inclusion in the cash working capital analyses. If Ms. Ebrey is of the opinion that the cash working capital analyses should include all cash outflows, (including capital costs), then all cash outflows associated with all other elements of the cash working capital analysis should be included as well. Finally, Ms. Ebrey's recommendation effectively ensures that the Companies' cash working capital requirements will be negative by including the capitalized costs associated with payroll in the expense portion of her analyses while only reflecting revenues which, in theory, match operating expenses.

The Commission agrees with the Ameren Companies for the reasons they offer and the Staff's position is rejected.

III. OPERATING EXPENSES AND REVENUES

A. Summary of Uncontested/Settled Issues

The agreed or accepted adjustments to operating expenses and revenues are as follows:

- Staff's proposed normalization of uncollectibles expenses (Resp. Ex. 16.0, p. 4);
- AMS reallocations for AmerenCILCO and AmerenCIPS (Resp. Ex. 16.7; Staff Ex. 12.0, Sch. 12.01, p. 2, col (1));
- Duplicate Charges (Resp. Ex. 36.0, p. 3);
- Electricity Distribution Tax for AmerenCIPS (Resp. Ex. 36.0, p. 31; Staff Ex. 12.0, Sch. 12.01, p. 2, col. (k));
- Property Insurance for AmerenIP (Staff Ex. 12.0, Sch. 12.01, p. 2, col (k); Resp. Ex. 16.3, Sch. 1, p. 2, col. (h));
- Purchase Accounting adjustment for Pension and OPEBs (Resp. Ex. 36.0, p. 9; Staff Ex. 12.0, Sch. 12.02, p. 2, col (k)); and
- Administrative Fees for Add On Taxes (Resp. Ex. 36.0, p. 3; AG Ex. 3.0, p.2).

Certain issues regarding Injuries and Damages expenses (Resp. Ex. 16.0, p. 8), and Major Medical expenses (Resp. Ex. 16.0, pp. 9-10) were resolved between the Ameren Companies and Staff, but remained contested with the AG.

B. Vegetation Management/Tree Trimming

The Ameren Companies have provided extensive documentation in support of their tree trimming costs and in rebuttal and surrebuttal testimony from two separate witnesses, Ron Stafford and Ray Wiesehan. While the Cities presented direct testimony questioning those costs, the Cities did not refute the Ameren Companies' rebuttal testimony and have apparently abandoned this issue. Staff did not question the Ameren Companies' tree trimming costs, except with respect to Staff's proposed new "no-touch" tree trimming policy.

Currently, the Ameren Companies trim at four-year intervals. Mr. Wiesehan testified that, in order to comply with Staff's new no-touch policy, the Ameren Companies would have to convert to a two-year trimming cycle. Respondents' Exhibit 16.5 shows that the Ameren Companies' additional costs for the No Touch Policy Adjustment would increase operating expense by $27,538,000. Of this total, $17,535,000 is incremental additional ongoing costs, and the remaining $10,003,000 reflects an amortization of the additional costs that will be incurred over the next four years, in order to convert from a four-year to a two-year tree trimming cycle. The increase in operating expense of $27,538,000 is also included in the Adjustments to Operating Income shown on Exhibits 16.1, 16.2, and 16.3. (Resp. Ex. 16.0, pp. 5-6.) The total additional cost to achieve and maintain a "no touch" program over a four year period is $57,548,000. (Resp. Ex. 25.0, pp. 11-12.) The Ameren Companies estimate that it will take four years to train new trimming personnel and integrate a no-touch approach into our program. (*Id.*) These costs are hardly insignificant.

Mr. Spencer concluded that Staff's new approach regarding NESC Rule 218 will not have a significant impact on tree trimming costs. Mr. Spencer also admits that he does not know that this is the case. (ICC Staff Ex. 10.0, p. 23, lines 577-78.) Notably, Staff has provided no analysis from any accounting or other expert to support this claim. No Staff witness took issue with any of the aforementioned dollar amounts. No Staff witness sought to undermine the above analysis.

Mr. Wiesehan explained why Mr. Spencer's claim is not true:

> First, there is not a homogenous growth rate among the tree species that get trimmed every year. Some trees respond differently to pruning. In order to maintain a true no contact program, some trees may be required to be trimmed as frequently as every year. Second, the Ameren Companies would have to employ additional staff to manage the resources required to maintain a no touch program. Our cost estimates for maintaining a no touch program are based upon trimming our entire system at a minimum every two years vs. every four years, as well as continuing to do some hot spot trimming to control trees that have extremely fast growth rates. These numbers reflect only the cost for contracted services and do not include any internal loading for additional staff Ameren would have to hire to administrate a no touch program. These financial projections assume we continue to manage for removals of new trees and brush and continue to maintain our current overhanging trim practices.

(Resp. Ex. 25.0, pp. 11-12.)

Mr. Wiesehan further testified that the no-touch policy would necessitate a two-year tree trimming cycle because the utilities would need to manage a narrowed space around the primary electric conductor. (Resp. Ex. 25.0, pp. 9-10.) The primary conductor is the wire that distributes higher voltage electricity to the transformers located on poles of the overhead distribution system. Mr. Wiesehan notes that several industry sources support this conclusion. (*Id.*) For example, results from an Environmental Consultants Incorporated ("ECI") study entered into the record shows this type of growth is a low risk to reliability. (*Id.*) The ECI study also suggests that preventative maintenance cycle period can be based on an economically optimal period rather than strictly on the basis of maintaining line clearance. (*Id.*)

Mr. Wiesehan agreed the Ameren Companies could trim this growth more frequently; however, at current funding levels we would be forced to manage a narrower window of around the conductor, i.e more time and expense incurred. (*Id.*) Consequently, the Ameren Companies would not pull as much growth from overhanging branches as we currently do nor remove as many volunteer or trapped trees. (*Id.*) This would lead to more trees having to be trimmed and a greater potential for overhanging limbs to break and contact the conductor, causing greater safety concerns to the general public and utility workers and poorer reliability performance. (*Id.*) This quote from the ECI study supports the Ameren Companies' position:

> "Branch diameter was shown to play a major role in conductivity, with the largest branches being much more conductive than small shoots. This work also suggests that the majorities of tree-to-conductor contacts result in high impedance faults of low current, and are relatively low risk to reliability."

(Resp. Ex. 25.0, p. 10, *quoting* Environmental Consultants Incorporated, "Species-Specific Variation in Impedance as Related to Electrical Fault Potential," June 2004.)

Further, Mr. Wiesehan testified that by not controlling new volunteer trees and brush, the Ameren Companies will have more trees to trim in the future:

> This will increase the cost and the resources required to maintain the system. Qualified trimming personnel are currently at a premium as are many skilled craftsmen. It would take several years to recruit and train new personnel. We would also have to take into consideration the impact on customer satisfaction. We would be on the customer's property more frequently, with no evidence of any enhanced benefit with regard to safety and improved reliability. In addition, we will be wounding trees more frequently with increased pruning and this could inhibit the trees' ability to properly compartmentalize the wound. This leads to an increase in stress on the trees, which in turn causes declining health to tree populations near the conductors, which again comes back to public safety concerns, reduced reliability and increased cost.

(Resp. Ex. 25.0, pp. 10-11.)

The Commission concludes that there is no support for Mr. Spencer's claim that costs to implement the "no-touch" policy would be offset by decreases in O&M expenses. Notably, Mr. Spencer has offered nothing to support his contention, and establishes no relationship between the Ameren Companies' level of tree trimming expense and their level of outage costs. Mr. Spencer admits that he has not attempted to quantify any savings in O&M. (ICC Staff Ex. 21.0, p. 17.) Accordingly, there is no factual basis upon which the Commission could conclude that any increase in tree trimming expense would be offset by decreased outage costs. (Resp. Ex. 16.0, p. 6.)

The Commission rejects Staff's new proposed "no-touch" policy for the reasons offered by the Ameren Companies.

C. Injuries and Damages Expense

In rebuttal testimony (Resp. Ex. 16.0, p. 8.), the Ameren Companies agreed to normalize injuries and damages expenses per Staff's recommendation in the direct testimony of Burma Jones. The AG offered a different proposal.

Both Ms. Jones and AG witness David Effron recommended normalizing injuries and damages expenses in their direct testimony. (ICC Staff Ex. 3.0, pp. 22-26; AG Ex. 1.0, pp. 17-19.) Ms. Jones recommends normalizing expenses over a four-year period, calculating the percent of claims charged against the reserve to the amounts accrued to the reserve. Ms Jones also recommends eliminating abnormal data to avoid skewing the resulting average. Mr. Effron disagrees with this approach, and recommends normalizing expenses over a five-year period.

Staff's weighted average approach is the preferred method in this case. A weighted average approach to normalization is more common and generally preferred in setting various revenue and expense levels rather than the simple average normalization developed by Mr. Effron. (Resp. Ex. 36.0, pp. 5-6.) Ms. Jones' approach recognizes that injuries and damages accruals and payments fluctuate from year to year. Notably, Mr. Effron has not opposed Staff's proposed weighted average approach to normalization of uncollectible expenses. A weighted average approach is commonly used in a ratemaking context normalize for variables such as weather, changes in depreciation rates, and cost of debt and equity.

D. Rate Case Expense

The Ameren Companies are entitled to recover their reasonably incurred rate case expenses. Staff, however, has inexplicably chosen to disallow a large portion of the Ameren Companies' reasonably incurred rate case expenses, without logical explanation.

These adjustments fall into three categories:

1) an undefined class of delivery service rate case expense costs that Staff claims has not been supported by documentation,

2) the cost of the Ameren Companies' rate case to establish a means for procuring power after December 31, 2006; and

3) the cost of an electric depreciation study that the Ameren Companies used to determine appropriate depreciation rates.

1. Delivery Services

The Ameren Companies have requested recovery of approximately $2.7 million in rate case expenses for this case, as the total amount of expenses for all utilities combined. (Resp. Ex. 16.9; ICC Staff Ex. 14.0, p. 1; Resp. Ex. 36.5, page 1.) The Ameren Companies stated that, to put this number in perspective, the Commission recently approved Commonwealth Edison's recovery of approximately $7.3 million in rate case expenses for their delivery services rate case expenses. (Final Order, ICC Docket 05-0597, p. 47; *see also* Resp. Ex. 36.0, p. 12.) That level of expense is consistent with rate case expenses approved for Commonwealth Edison in other cases. (Final Order, ICC Docket 05-0597, p. 47.) While Commonwealth Edison is able to spread its rate case expenses over a larger customer base, fewer customers does not mean less work for the Ameren Companies in litigating their rate cases.

The Ameren Companies state that this level of expense demonstrates that the Ameren Companies have diligently managed the rate case expenses for three utilities at a level far below what the Commission, and Staff, has deemed reasonable for one.

Staff does not dispute that rate cases take time, and that the time of an expert or an attorney costs money. (*Id.*; Tr. at pp. 583-85.) Staff has been provided with the hourly rates of the Ameren Companies' expert witnesses and counsel in the form of contracts and "numerous" invoices, as well as total cost estimates for those services. (*Id.*; ICC Staff Ex. 14.0, p. 5.) Staff has acknowledged that the Ameren Companies have incurred costs since their rebuttal filing. (Tr. at 581, lines 21-22, Tr. at 582, lines 1-2.) Staff agrees that their costs are ongoing. (Tr. at 587, lines 12-16.) But Staff has chosen to disregard that information. Staff has not analyzed or reached any determination of whether the Ameren Companies are being overcharged at the rates indicated in contracts and invoices, or whether the total requested amounts for those services are unreasonable. (Tr. at p. 608, lines 2-22, p. 609, lines 1-14.)

Staff's only apparent basis for the recommended disallowance is that the Ameren Companies' rate case estimates at time of filing were lower than their estimates at the rebuttal stage. (ICC Staff Ex. 14.0, p. 4.) Working backward, Ms. Jones speculates that this overly optimistic cost estimate must have been the result of "verbal communications with [the Companies'] outside service providers." (ICC Staff Ex. 14.0, p. 4.) Ms. Jones ultimately concludes that "verbal communications" are inherently unreliable. (Tr. at p. 606.) Thus, any costs that have not been invoiced are unreasonable.

Ms Jones has admitted that the Ameren Companies are allowed to recover their reasonable rate case expenses, regardless of whether they have already been invoiced. (Resp. Exhibit 36.0, p. 10.) Yet, the gist of Ms. Jones' testimony and recommendation is that if a cost has not been invoiced and paid, it is not reasonable and may not be recovered. (*See* Tr. at p. 589.) Ms. Jones has not identified any particular rate case expense that she believes is unsupported, and has not found any particular cost to be unreasonable.

The Ameren Companies strongly disagree with Ms. Jones' opinion. Mr. Stafford testified that the Ameren Companies used the most accurate information available at the time of filing – including service provider rates, contracts, letters of engagement and historical data, and yes, spoken communication – to derive their original cost estimates. (Resp. Ex. 36.0, pp. 11-12.) The Ameren Companies have cultivated long relationships with many of the service providers they use in a rate case, and thus are able to use historical data and experience to shape cost estimates.

The record is clear that the Ameren Companies have managed to keep their rate case expenses to an extraordinarily low level, a level far below what the Commission has deemed reasonable in other cases. The Ameren Companies provided ample support for all of their rate case costs, including the most accurate estimates available, contracts, letters of engagement, and "numerous invoices." Staff's proposed disallowance is without merit and is rejected.

2. Post-2006 Basic Generation Services

There are two unresolved issues related to the Ameren Companies' Post-2006 Basic Generation Services rate case ("Post-2006 Rate Case").

First, similar to its position regarding delivery services rate case expenses, Staff has recommended only those costs which have been invoiced to date. (*See* ICC Staff Ex. 14.0, Schedule 14.02, p. 1.) As in this case, the record indicates that the Ameren Companies' expenses in the Post-2006 Rate Case are necessary, unavoidable and ongoing. Staff has not disputed this fact. For the same reasons discussed above, Staff's recommended disallowance of Post-2006 Rate Case expenses not invoiced to date rejected.

Second, Staff has recommended disallowing recovery of rate case expenses related to the Post-2006 Rate Case through delivery services rates. Staff instead recommends recovering those expenses through the SPA. (ICC Staff Ex. 14.0, p. 10-12).

The Commission disagrees. The BGS case benefits all delivery services customers and it is appropriate to recover those costs through delivery services rates established in this case.

3. Depreciation Study

In preparation for this rate case, the Ameren Companies commissioned a depreciation study to determine the Ameren Companies' current appropriate depreciation rates. (Resp. Ex. 36.0, p. 14.) The Ameren Companies state that the depreciation study was an important and necessary expenditure to determine appropriate depreciation rates for all of the Ameren Companies, especially because the Companies' rates have been frozen for almost ten years. (*Id.*)

Staff recommended disallowing recovery of expenses the Ameren Companies incurred in conducting its depreciation study (Staff Ex. 3.0, p. 24). Ms. Jones testified that expenditures related to the depreciation study are not a recoverable rate case expense, because the Ameren Companies have not proposed any changes in depreciation rates. (Staff Ex. 14.0, p. 10.)

The record shows that the depreciation study supported a small decrease in depreciation rates for AmerenCIPS and AmerenCILCO, but a very large increase in depreciation rates for AmerenIP. (Resp. Ex. 36.0, p. 15.) Mr. Stafford explained that the Ameren Companies analyzed the results of the study, and the decision not to request a change in depreciation rates was based on these results. (Resp. Ex. 36.0, pp. 15-16.) Although the results of the depreciation study supported a moderate overall increase in expense, there was a large disparity between the increase in rates recommended for AmerenIP versus the other utilities. (*Id.*) This increase would have caused AmerenIP's rates to jump substantially higher. (*Id.*) Because the Ameren Companies are very concerned about the affect of an increase in rates on our customers, the decision was made that an increase in depreciation rates would not be requested until a more complete history of ownership for all of the utilities had been established. (*Id.*) Notably, Staff did not recommend an increase in depreciation rates for any of the utilities, either.

The Commissiona agrees with the Ameren Companies' and Staff's proposal is rejected. The Ameren Companies' decision to limit depreciation rate increases in the present circumstances appears reasonable.

E. A&G Expenses

1. Functionalization

Staff witness Lazare and IIEC witness Chalfant, challenged the level of A&G expenses for the Ameren Companies. ICC Staff Ex. 17.0, pp. 10-28; IIEC Ex. 5.0, pp. 10-16. Both approaches rely on a generalized view of A&G, rather than a review of specific A&G expenses.

Mr. Stafford explained that, to the extent test year A&G expenses support non-regulated production functions, the Ameren Companies have assigned an allocable portion of test year A&G expenses to non-regulated production functions on the books of AmerenCILCO and AmerenIP. In the test year, AmerenCIPS did not own any production assets, nor did they have any employees assigned to production. Therefore, no A&G expenses were assigned to non-regulated production for AmerenCIPS. Resp Ex. 36.0, pp.21-22. He also explained that none of the the test year A&G expenses support non-regulated production functions of other Ameren affiliates involved in the generation of electricity, because A&G expenses supporting non-regulated production functions of other Ameren affiliates are recorded on the books of the other Ameren affiliates. No portion of the costs recorded on the books of the other Ameren affiliates also included in the requested level of A&G for AmerenCILCO and AmerenCIPS. *Id.* at 23-24.

Mr. Stafford also explained that Ameren determines whether A&G expenses should be recorded on the books of the Ameren Companies vs. other Ameren affiliates based on the work being performed. If an employee of AmerenCIPS, for example, charges his/her time to an A&G account, and he/she performs work for another affiliate, then the affiliate will be issued a bill for that work, and reimbursement to AmerenCIPS will be recorded as a reduction to A&G expense. If that same employee routinely performs work for other Ameren affiliates, that employee would instead be employed by Ameren Services Company. In that case, time reporting would be governed by the General Services Agreement ("GSA"). In the example used above, the employee performing work on behalf of the other affiliate would have the ability to directly assign such time to the affiliate. The A&G expense associated with the specific work performed would in turn be recorded on the books of that affiliate. If instead the work performed were to benefit more than one Ameren affiliate, the GSA provides a number of different allocation methods that could be used to allocate costs common to more than one legal entity, within the Ameren affiliate group of companies. Resp. Ex. 36.0 at 24.

Both Mr. Lazare and Mr. Chalfant suggest that there should be a relationship between A&G and other O&M expenses. The Ameren Companies explained that there is no basis for such a relationship. To provide context for this issue, Mr. Stafford reviewed the Ameren Companies' O&M and A&G expenses compared with a proxy group of ten other utilities with similar megawatt hours and customers. He found the Ameren Companies compare very favorably with the other utilities for A&G expenses in relationship to other O&M expenses. More specifically, in the Ameren Companies' surrebuttal filing, A&G expenses divided by distribution plus customer expenses, is 76.01%. This compares with the ten-utility proxy group average of 104.51%. As such, even if the argument could be made that there is a direct relationship between A&G other O&M, then the overall level of A&G costs requested by the Ameren Companies is reasonable. Resp. Ex. 36.0 at 25-26.

With regard to his proposal not to use the AmerenIP results, Mr. Lazare argued that "there must be some evidence to indicate that the company should receive an even greater increase than it proposed in direct". Mr. Lazare, however, did not identify any valid reason for not making the adjustment, other than he does not like the results. There are numerous reasons why this logic is faulty. First, Mr. Lazare has not identified any statutory or legal restriction on the ability of Staff witnesses to propose a greater increase for a particular cost, or group of costs, that a company proposes. Second, Staff witnesses have accepted a number of adjustments and corrections to what the Ameren Companies originally proposed in these proceedings. Some of these adjustments, such as corrections to the AMS Reallocation, and updated Rate Case expense, have resulted in increases. In addition, Mr. Lazare himself is inconsistent in approach, in that he has proposed an increase to AmerenCILCO general and intangible plant compared to the Ameren Companies' proposal. In the case of general and intangible plant, Mr. Lazare was consistent in that he proposed a uniform approach, whether positive or negative, for each of the Ameren Companies, but for some reason, he has elected to not follow a uniform approach for A&G expenses. Resp. Ex. 36.0, p. 29.

The record shows that the Ameren Companies have supported their requested level of A&G costs, have demonstrated that such costs are reasonable both in total in comparison with other O&M expenses, and have provided detailed support for not only pensions and benefits costs, but also for other A&G costs. In addition, the Ameren Companies have supported the fact that other Ameren affiliates involved in non-regulated production functions have substantial A&G costs independent of the costs recorded on the books of the Ameren Companies. The burden of proof has been met by the Ameren Companies in these proceedings to demonstrate that the requested level of A&G costs are reasonable. Further, neither Mr. Lazare nor Mr.

Chalfant identified a single cost that is imprudent. Neither Mr. Lazare nor Mr. Chalfant has identified a single A&G cost that is not properly allocated to the Ameren Companies. Accordingly, the Staff and IIEC adjustments are rejected.

2. Incentive Compensation

The Ameren Companies have requested full recovery of their incentive compensation costs through rates. They state that the record shows that incentive compensation costs are a necessary component of the Ameren Companies' compensation package, and thus should be recoverable in rates. Further, Staff witness Jones' testimony concedes that ratepayers are at least partial beneficiaries of the Ameren Companies' incentive compensation payouts (ICC Staff Ex. 14.0, p. 13, lines 250-51), thus supporting at least a partial recovery of incentive compensation costs.

Ameren Companies' witness Krista Bauer testified that incentive compensation payouts are a standard business practice that is necessary for any business to attract and maintain a well-qualified, efficient, and focused workforce. (Resp. Ex. 44.0, pp. 1-2.) Incentive compensation does not merely give the Ameren Companies a competitive edge in attracting employees – incentive compensation is an essential component of a fair and market-based compensation package. (*Id.*)

The ratepayers' and the Ameren Companies' interests are aligned on this point. Ratepayers need the Ameren Companies to be able to compete with other companies for the best and most qualified employees. Reliable and efficient electricity service depends on it. The alternative to offering a competitive compensation package consisting of both base and incentive pay is to simply eliminate incentive pay, which would likely increase fixed labor costs and reduce employee interest/focus on key operational goals. This arrangement would not benefit anyone, most importantly the ratepayers.

Ratepayers also benefit from incentive compensation payouts through realization of operational goals, motivated by the incentive payout formulas. (*Id.*) Incentive payouts are driven by performance on key customer-focused operational metrics. (*Id.*) The quality utility service that our customers are receiving is dependent on high performance from employees who are focused on the Ameren Companies' operational goals.

The Ameren Companies use many customer-focused incentive compensation goals/measures to focus their employees' efforts on activities that will benefit customers. (*Id.* at p. 3.) The Ameren Companies are consistently concerned with ensuring reliable service to customers. As a result, measures of electricity reliability are regularly placed on scorecards and used to determine incentive compensation payouts. (*Id.*) For example, the Ameren Companies' employees have shared goals to reduce the frequency of electric service disruptions in each of the divisions they serve. (*Id.*) Responding to one of Mr. Effron's points, this is but one example of enhanced efficiencies achieved through incentive compensation payouts.

In addition, the Ameren Companies' employees have goals to decrease the duration of any interruptions that may occur by quickly restoring service to the customer. (*Id.*) To facilitate these goals, employee teams are formed to identify and implement process improvements. (*Id.*) Undeniably, a strong focus on increasing service reliability benefits every customer in the Ameren Companies' territory.

Another key metric on which the Ameren Companies base incentive awards is customer satisfaction. (*Id*.) Customer satisfaction is regularly measured and analyzed to determine how to improve service even more. (*Id.*) This focus on customer satisfaction has resulted in many activities designed to enhance the customer experience, with respect to both the contact center and field services. (*Id.*) Our focus and measurement of customer service has resulted in both

AmerenCIPS and AmerenCILCO recently receiving certification by JD Powers for Call Center Operations. Undeniably, a strong, incentive-based focus on increasing both the technical and professional service that customers receive when interacting with the Ameren Companies directly benefits their customers. (*Id.*)

Another salient metric used to measure incentive-based payouts is safety, as measured by lost workday away cases. (*Id.*) Reducing lost workdays serves to reduce operating costs, another concern raised by Mr. Effron.

When Ameren Company employees do not work in a safe manner, they risk serious injury to themselves and/or others. (*Id.* at 4.) One of the results of injury is that employees spend time off work and are unable to provide service to the customer. Ameren and its subsidiaries have continued to place a greater and greater emphasis on safety and are heavily reinforcing this measure by giving it significant weight in incentive calculations. (*Id.*) The Ameren Companies have seen many initiatives designed to increase safe work practices and as a result, a fairly significant decrease in lost workday away cases. (*Id.*) Again, this is a practice that undeniably benefits the customer. Ultimately, Ameren's key performance indicators, reinforced by incentive payouts, have resulted in significant attention to important customer issues. This focus has resulted in both tangible benefits (such as JD Power Certification and reduced lost workday away cases, etc.) and intangible benefits (employee alignment with key goals, prioritization of goals, etc) (*Id.*) – all of which help the Ameren Companies provide safe, and reliable service to our customers.

The Ameren Companies recognize that employee motivation is necessary to align individual goals with the Ameren Companies' operational goals. Incentive compensation programs motivate employee behavior by focusing employees on important business and operational goals and rewarding them when they achieve or make progress towards the goals.

Incentive compensation is a critical tool for attracting, motivating and retaining the Ameren Companies' employees. (*Id.* at 6.) Historically, the Ameren Companies' plans have been funded and have provided employees with rewards for both group and individual performance. (*Id.*) Our intention is to continue this practice.

The record supports the Ameren Companies full recovery of incentive compensation benefits.

3. Pension and OPEB Expense

ICC Staff witness Peter Lazare, IIEC witness Alan Chalfant, and Wal-Mart witness James T. Selecky each raised certain issues directly or indirectly pertaining to pension and/or OPEB benefits, those issues were addressed in significant detail in the rebuttal testimony of Ameren Companies' witness C. Kenneth Vogl, Respondents' Ex. 21.0 (see also AmerenCILCO, AmerenCIPS, and AmerenIP Ex. 11.0 for discussion of relevant issues). Those issues, described briefly below, are apparently resolved, as none of those witnesses disputed or questioned Mr. Vogl's testimony in their respective rebuttal testimony. Additionally, the AG raised issues that are addressed below.

a. ICC Staff

In his direct and rebuttal testimony, Mr. Vogl explained the key factors driving the increases in pension and OPEB expenses are interest rates, returns on equity investments, and medical inflation – factors beyond the control of the Ameren Companies. While Mr. Lazare questioned this in his direct testimony, he did not dispute Mr. Vogl's testimony on rebuttal, apparently accepting Mr. Vogl's numbers and explanations of why increases in pension and

OPEB have occurred and why the pro forma levels accurately reflect the Ameren Companies' actual, recoverable expenses.

b. IIEC

IIEC witness Alan Chalfant testified: "To the extent the commission approves increased amounts of O&M expense for the adequate provision of delivery service, the amount of overhead or A&G should be increased proportionally."

Pension and OPEB expenses represent 49.6% of the increase in A&G expenses since the prior order. As detailed above, and as Mr. Vogl explained in his direct and rebuttal testimony, pension and OPEB expenses have increased dramatically since each of the Ameren Companies' last delivery services case. Pension and OPEB expenses included in the prior orders for the Ameren Companies reflected the Ameren plans at a time when they were more fully funded, as a result of the then current economic environment. In fact, the pension plans were overfunded. Due to subsequent investment performance, decreasing interest rates, and high medical inflation, the plans have become more underfunded. The pension (FAS 87) and OPEB (FAS 106) expenses included in the current case reflect the expenses of Ameren's underfunded plans, and these expenses are reasonable compared to pension and OPEB expenses for similarly sized organizations.

At the same time that plans have become underfunded, all companies offering such benefits have seen a significant increase in pension and OPEB expenses. The increases in pension and OPEB expenses are primarily the result of changes in interest rates, returns on equity investments, and medical inflation.

Thus, Mr. Vogl's testimony demonstrates that a large percentage of A&G expenses are unlikely to be correlated to any increase in O&M expense, which are not generally subject to the same pressures and drivers. Mr. Chalfant did not dispute Mr. Vogl's testimony on rebuttal.

c. Wal-Mart

In his direct testimony, Mr. Selecky recommended "that the ICC approve a normalized level of pension and OPEB expenses to be included in Ameren Utilities' revenue requirements". (Wal-Mart Ex. 1.0., p. 33.) His approach averages the past five years of pension and OPEB expenses to determine the normalized expense amounts. As explained in Mr. Vogl's rebuttal testimony (Resp. Ex. 21.0, pp. 8-9) and below, Mr. Selecky's recommendation is incorrect. Notably, Wal-Mart did not dispute in rebuttal the Ameren Companies' testimony regarding why Mr. Selecky's recommendation is not reasonable.

First, the only correct approach for rate recovery of pension and OPEB expenses allows for the Ameren Companies' full recovery of these expenses over time, no more and no less. As Mr. Vogl discussed in his direct testimony, and as Mr. Selecky agreed, pension and OPEB expenses can be very volatile. Mr. Selecky's proposed approach normalizes the peaks (high cost periods) while ignoring the valleys (low cost periods). Mr. Vogl testified that this approach would result in less than full pension and OPEB expenses being reimbursed by ratepayers.

Again, it is important to note that the pension and OPEB expenses approved in the prior orders were very low. These prior orders' expenses for 1999 or 2000 reflect expenses for overfunded plans that were generated by the high equity returns, higher interest rates, and lower medical costs during the late 1990s. In essence, the change in pension and OPEB expense since the prior orders simply reflects the adjustment in economic environment.

Second, pension and OPEB expenses for any given year should be equal to the benefits earned in that year plus an adjustment based on the funded status of the plan, according to FAS 87 and FAS 106, which are both in accordance with Generally Accepted Accounting Principals. (FAS 87 and 106 are explained in detail in Mr. Vogl's direct testimony, (AmerenCILCO, AmerenCIPS, and AmerenIP Ex. 11.0.) Since both FAS 87 and FAS 106 determine expense for the pension and OPEB plans in this manner, these expenses should be reimbursed by ratepayers on the same basis, thus ensuring that the pension and OPEB expense for any given year is tied to the current funded position of the plans. Normalizing the pension and OPEB expense so the costs are not representative of the current funded position would be inconsistent with ratemaking principles, as it would yield pension and OPEB expenses that are significantly different than the current funded position of the plans.

Ameren Companies' witness Kenneth Vogl testified that the Ameren Companies, similar to the majority of other companies, have experienced significant increases to their FAS 87 and FAS 106 expenses over the past few years. Mr. Vogl explained the key reasons for these increases, specifically, the fact that lower discount rates and higher medical costs have increased the Companies' liabilities, and that lower than expected investment returns (which result in fewer plan assets than expected), have lowered the funded status of the pension and OPEB plans.

d. AG

Additionally, the AG opposed the use of the Companies' 2006 actuarial estimate to develop pension expense, instead recommending the use of an historical actuarial study. The Companies provided a number of reasons why it is most appropriate to use 2006 information to determine pensions and benefits expenses:

- 2006 data includes a full year of Illinois Power on the Ameren financial system. Thus, 2006 data more accurately reflects AmerenIP's allocable share of pensions and other post employment benefits expense.
- 2006 data also includes a full year of the transfer of the former IllinoisUE employees to AmerenCIPS, and therefore reflects a more accurate determination of the impact of pensions and benefits costs of AmerenCIPS.
- 2006 data more closely coincides with the date new rates will go into effect as a result of these proceedings. (January 2, 2007).

- Reasonably certain changes in cost components (such as medical inflation rates and plan changes) are reflected in 2006 estimates, but would not be fully reflected, or reflected at all, in 2005 actual data.
- 2006 data thus satisfies the criteria established in Section 287.40 of the Illinois Administrative Code for use of estimates in establishing rates.

The Ameren Companies explained that, while actuarial studies provide useful information and are very helpful in measuring the overall levels of, and changes in, plan costs, for a period of time, costs begin to change immediately after the study date. Even if there were no change in eligible participants, and no change in the assumption for inflation rates and return on plan assets, costs would immediately change due to changes in service plan costs, and changes in the amortization of plan gains or losses. Such costs may increase or they may decrease, but they will change. Therefore, it is generally more appropriate to use more current information to establish such costs, including consideration by the actuary of anticipated changes in cost components, such as medical inflation rates and other plan changes – especially considering the fact that rates to be established in this case will not go into effect until January 2, 2007, well after the 2005 study period recommended by Mr. Effron. (*Id.*)

Accordingly, the record demonstrates that the Ameren Companies' estimates are reasonably expected to be representative of going-forward levels, and are more accurate than the actual 2005 data, and the Commission adopts the Ameren Companies' 2006 actuarial estimates as proposed.

4. Other A&G - Effect of Ameren Ownership on Illinois Power Expenses

The AG took issue with the reflection of certain AMS costs in the test year for AmerenIP. Specifically, the AG argues that the balance of costs and benefits from Ameren's acquisition of what we now call AmerenIP was established in Docket No. 04-0294, that the balance must not be “upset” and that the AMS costs allocated to AmerenIP exceed a reasonable allowance for Dynegy costs by approximately $4.7 million.

The Ameren Companies stated that Mr. Effron’s analysis is questionable, at best. As with any acquisition, it is difficult to determine what actual costs of service would have been had the transaction not occurred. Such comparisons are speculative. While the kind of comparison Mr. Effron is attempting to make can be useful, there are problems in the numbers he uses. Specifically, the 2004 Dynegy allocation he uses is inappropriate for such a comparison.

Mr. Porter identified the adjustments that would need to be made to the Dynegy allocation to result in a valid comparison. First, Mr. Effron’s adjustment for injuries and damages should be eliminated. At the time Mr. Effron filed his testimony this adjustment was valid. However, the Company has since accepted an adjustment to the injuries and damages amount on Schedule C-2.12 for the amount of the Dynegy allocated costs. Therefore, the adjustment is no longer needed. Eliminating this adjustment increases the Dynegy value from $13.5 million to $17.4 million. (Resp. Ex. 32.0, pp. 2-3.)

Second, the Dynegy allocation for 2004 represents only nine months of allocated costs and should be adjusted to reflect a full year under Dynegy ownership. If Dynegy had owned IP for the entire year, the cost would have been $23.1 million based on a simple extrapolation of the first nine months. Resp. Ex. 32.0, p. 3.

Third, Dynegy was already in the process of reducing its corporate support structure to reflect a change in focus to its core business. Prior to changes in Dynegy’s corporate cost structure, the annual corporate allocation to IP was in excess of $40 million. Only after Dynegy was led by its circumstances to take a shorter-term business focus was the level of allocation to IP reduced to its 2004 level. Since IP would most likely have continued under Dynegy ownership only in the absence of Dynegy's financial challenges, it is more appropriate to use a historical average of the allocated corporate costs as an indication of what costs would have been under continued Dynegy ownership. Using the above-mentioned $23.1 million for a full year of 2004 costs, the average annual allocated corporate costs from 2001-2004 were $27.1 million. (Resp. Ex. 32.0, pp. 3-4.)

Finally, the Dynegy allocated costs are in 2004 dollars whereas the AMS costs are in 2006 dollars. Adjusting for two years of wage increases and general inflation brings the annual value for the Dynegy allocation to $29.3 million. *Id.*

Hence, Mr. Porter showed that the expected AMS allocation of A&G costs of $28.6 million is less than the estimated allocation of Dynegy A&G costs of $29.3 million. Therefore, no adjustment to O&M expense should be made based on differences in corporate A&G allocated costs.

Moreover, the "balance" the AG refers to involves more than allocated A&G costs, as Mr. Porter explained. The AG fails to take into account other benefits resulting from the acquisition of IP by Ameren, such as reductions in debt interest, depreciation expense, and fuel costs. The cost of capital presented in Company witness McShane's direct testimony reflects reductions in high cost debt issued by IP under Dynegy ownership. Changes in depreciation expense resulting from the acquisition of IP by Ameren are included in schedules filed with the Company's initial request and sponsored by Company witness Stafford. Benefits related to improvements in service and overall financial health are also ignored in Mr. Effron's analysis. All benefits of the acquisition, both quantitative and qualitative, must be included in any analysis of the overall costs and benefits to customers. Rep. Ex. 32.0, p. 4.

While noting that any such comparison would still be speculative, Mr. Porter explained that the qualitative benefits of the transaction have been substantial. Resp. Ex. 32.0, pp. 4-8. He listed many of them, which the Commission will not repeat here.

Accordingly, there is no basis for the AG's adjustment, and it is rejected.

IIEC also offers an adjustment here. Mr. Gorman proposes a reduction in the amortization of the acquisition cost regulatory asset based on the premise that the Company has not met the commitments it made as outlined in the Commission's Order in Docket 04-0294. Mr. Gorman cites a portion of the Commission's conclusion in Finding 7 beginning on page 24 of the Order. The quoted portion is stated as follows, with emphasis shown as in Mr. Gorman's testimony:

> "**Commission Conclusion**: The Commission finds that Ameren, AG, and CUB have agreed that, with the conditions agreed to by Ameren, including Conditions 19 through 25 on Appendix A to this Order, the record supports a conclusion that the <u>Reorganization is not likely to result in any adverse rate impacts for retail customers</u>. No other party has disputed this conclusion. While there was some disagreement in the record as to the specific amounts of savings that IP will achieve after closing, <u>Ameren has agreed to measures to assure that IP is taking adequate steps to produce savings and to impose quantifiable measures to insure that rates are not increased if savings fail to materialize</u>." (ICC Docket No. 04-0294, Order, September 22, 2004, p. 24)

Mr. Gorman asserts that the Company has not met its commitments with respect to the estimated synergy savings based on information provided in my direct testimony, which shows that the estimated synergy savings had not yet been achieved.

Mr. Porter explained that the portion of the Commission Order in Docket 04-0294 cited by Mr. Gorman refers to Commitments 19 through 25 of Appendix A to the Order. Commitments 21 through 23 address the treatment of synergy savings for purposes of setting

> 21. In its next electric rate case and next gas rate case, IP will file as a component of its initial filing a report (verified by a witness in the case) detailing the milestones achieved as well as other identified savings. The verified report shall provide information current as of the time of the rate filing.
>
> 22. In IP's next electric rate case and next gas rate case, for all Associated Savings Amounts not reflected in the proposed test year, the Commission may reduce O&M expenses by the jurisdictional (i.e., electric vs. gas) portion of any Associated Savings Amount ("Jurisdictional O&M Reduction") for any milestone that IP has not achieved or cannot demonstrate that it is reasonably certain to achieve by the time the rates approved in that case go into effect…
>
> 23. In IP's next electric rate case and next gas rate case, IP will allocate Associated Savings Amounts on a basis consistent with the underlying O&M expenses to which they relate.

Resp. Ex. 32.0, pp. 8-11.

Mr. Porter provided the status of each milestone related to synergy savings, satisfying the terms of Commitment 21. Commitment 22 has been satisfied as shown in the Company's Schedule C-2, which includes a reduction to test year revenue requirements for savings not yet achieved, thus ensuring that all Associated Savings Amounts are reflected in the proposed test year. Commitment 23 has been satisfied as shown in the Company's Schedule C-2.4, in which savings are allocated to O&M accounts based on the costs to which the savings relate. Moreover, these savings were not offset by changes in the allocation of A&G costs from AMS to AmerenIP because the A&G costs allocated by AMS to AmerenIP are less than those that might have been allocated by Dynegy had the acquisition not occurred, based on historical costs. Id.

Mr. Gorman proposed a reduction to the Company's proposed amortization of acquisition cost regulatory asset. The Commission Order in Docket 04-0294 address treatment of these costs::

> "…the proposed allocation of savings and costs is reasonable, and that establishment of a regulatory asset of up to $67 million, to be

> amortized over the period 2007-2010, is acceptable and should be approved, subject to the conditions proposed by Staff and set forth in Paragraph 11 of Appendix A to this Order."

Paragraph 11 of Appendix A states that:

> "Except to the extent reflected in the regulatory asset approved in this Order, IP will not seek recovery in rate proceedings of: (i) the stock issuance costs associated with the equity issued by Ameren to acquire IP; (ii) the severance and relocation costs associated with the integration of IP into Ameren; (iii) the implementation costs associated with integration of IP into Ameren; (iv) any acquisition adjustment associated with the acquisition of IP by Ameren; and (v) any debt redemption costs associated with the recapitalization of IP described in Applicants' Ex. 24.1."

The record shows that the Company met the conditions of this commitment as it relates to this proceeding.. The Company has not included in its requested revenue requirement any of the costs proscribed by Paragraph 11. Resp. Ex. 32.0, pp. 8-11. Accordingly, there is no basis for IIEC's adjustment and it is rejected.

The Commission agrees with the Ameren Companies and the adjustments to these expenses are rejected.

IV. RATE OF RETURN

Issues that were resolved by agreement or acceptance involved:

- reacquisition losses associated with AmerenCILCO's preferred stock (Staff Ex. 16.0, p. 13; Resp. Ex. 35.0, p. 8);
- reacquisition gains associated with AmerenCILCO's preferred stock (Staff Ex. 16.0, p. 15; Resp. Ex. 15.0, pp. 5-6);
- issuance expense associated with AmerenCILCO's preferred stock series (Staff Ex. 16.0, p. 18);

- AmerenCIPS' premium and issuance expense associated with its preferred stock (Staff Ex. 16.0, p. 16);
- removal of total other comprehensive income ("OCI") from the common shareholder's equity balances (Resp. Ex. 15.0, pp. 5-6); and
- adjustments to AmerenCIPS' long-term components of its capital structure based on an AFUDC formula (Resp. Ex. 15.0, p. 10).

A. Capital Structure

1. Capital Structure Measurement Period

The Ameren Companies recommend measuring all components of the capital structure at 12/31/05, making the measurement period consistent with regard to all components. Resp. Ex. 15.1, p. 2.

Staff witness Pregozen recommended advancing the capital structure measurement dates for AmerenCILCO and AmerenCIPS in lieu of pro forma adjustments. The Companies agree with Mr. Pregozen's recommendation to advance the capital structure measurement dates rather than make pro forma adjustments in this instance. Resp. Ex. 15.1, p. 1. However, they disagree with Mr. Pregozen's use of a June 30, 2005 measurement date for all of the long-term components of AmerenCILCO's and AmerenCIPS' capital structures while using a last twelve months ("LTM") December 31, 2005 measurement period for short-term debt. Mr. Pregozen states in his direct testimony on lines 264-265 that 'advancing the measurement date ensures that all components of the capital structure are measured on a consistent basis. His approach does not achieve that consistency. Mr. Pregozen measures short-term debt over a period which lasts six months beyond the date at which he measures common equity, long-term debt and preferred stock. By doing this he has mismatched the measurement date of permanent capital balances with the ending date for the period for measuring short-term debt balances. *Id.* at 1-2.

The Ameren Companies state that their proposal eliminates any mismatch between the measurement date of the long-term components (common equity, long-term debt and preferred) with the measurement period of short-term debt. Furthermore, a consistent measurement period eliminates the need for the type of conjecture Mr. Pregozen undertook when he chose a twelve month period as 'a better estimator of the amount of short-term debt CILCO has maintained to finance its operation…' This is the sort of subjective speculation that the Commission no doubt sought to eliminate when it drafted its latest capital structure measurement period instructions as part of the filing requirements. Also, the buildup of short-term debt that Mr. Pregozen refers to is the type of pattern that can precede a replacement by a permanent capital source. *Id.* at 2-3.

The Companies also recommend measuring all components of AmerenIP's capital structure as of December 31, 2005. Again, for purposes of consistency the Companies would recommend measuring the balance of net short-term debt to LTM ended December 31, 2005. Moving forward the measurement dates for AmerenIP would be consistent with the measurement periods for AmerenCILCO and AmerenCIPS while incorporating the latest data available. Further, Statement of Financial Accounting Standards 141 allows for a period of one year following the closing date of the acquisition to identify, measure and assign amounts to purchase accounting adjustments. Since Ameren's acquisition of AmerenIP was completed on September 30, 2004, a capital structure date of December 31, 2005 would allow the Companies to incorporate final purchase accounting adjustments, while avoiding the need for either pro forma adjustments or estimated adjustments. Resp. Ex. 15.1, p. 3.

The Ameren Companies proposals are reasonable and they are accepted.

2. Imputed Capital Structure

The Ameren Companies and the Staff proposed using the Companies' actual capital structure, although they differed with respect to the proper measurement period. (See Section

III.B.1.) CUB witness Bodmer and IIEC witness Gorman proposed the use of hypothetical capital structures.

CUB witness Bodmer recommends developing hypothetical capital structures for AmerenCIPS, AmerenCILCO and AmerenIP that would be consistent with BBB ratings based on his analysis. Mr. Nickloy explained why this would not be reasonable. First, his analysis uses an approach based on S&P's financial ratio guidelines. Second, Mr. Bodmer is effectively arguing that AmerenCIPS' and AmerenCILCO's then "A" category ratings were too high and that a "BBB" is the "correct" or most reasonable rating category or level for a utility. As will be discussed, Mr. Bodmer almost got his wish – but at the present capital structure. See Ameren Freetly Cross Ex. 1. There is no room for further ratings degradation.

The equity ratio for each of AmerenCIPS, AmerenCILCO and AmerenIP has been taken into account by the rating agencies as part of their assignment of the ratings for these companies. For example, AmerenIP's equity ratio is a result of Ameren's recapitalization efforts at this utility. Notwithstanding this equity ratio, AmerenIP's ratings are only marginally within the investment grade category. If AmerenIP were to reduce its equity ratio, e.g. replace equity capital with debt capital, AmerenIP's key cash flow ratios would deteriorate and thus place negative pressure on AmerenIP's already marginal ratings. Resp. Ex. 14.0, p. 6.

Utilities are capital intensive businesses. Utilities have a fundamental responsibility to provide reliable utility services such as the provision of electricity or natural gas to their customers. Utilities must access capital to fund working capital requirements, to make continuing investment in their utility infrastructure, and replace existing capital as it matures. Resp. Ex. 14.0, p. 6. It naturally follows then that utilities must have reliable access to capital at reasonable cost. The credit quality of a utility is directly related to its ability to reliably access the credit and capital markets for the debt capital it requires and the cost of that capital. *Id.*

The Ameren Companies state that if the Commission were to accept Mr. Bodmer's premise that AmerenCIPS and AmerenCILCO are too highly rated, and accordingly, make adjustments to their allowed cost of capital based on this, the Commission would effectively be punishing these two utilities for their history of prudently financing and capitalizing their business and assets, and would be calling into question the utility managements' strategy of and commitment to maintaining strong investment grade utilities. An electric and gas transmission and distribution utility with an "A" category rating is not unusual nor is it unreasonable. In S&P's Regulated Transmission and Distribution – Electric, Gas and Water U.S. utility segment, there are 33 electric, gas or combination utilities with corporate credit ratings of A- or higher alone. This number does not include utilities with BBB+ corporate credit ratings and A- ratings for their senior secured/first mortgage debt. Resp. Ex. 14.0, p. 7.

At BBB, a utility is only two ratings notches away from having sub-investment grade, or junk, ratings - a ratings situation which plagued Illinois Power Company prior to its acquisition by Ameren and a ratings situation which plagued the prior parent companies of both AmerenCILCO and AmerenIP. Two notches is not a lot of "ratings cushion" to absorb factors or conditions which could apply negative pressure to the ratings. As we have seen, these factors can include a political environment which places risk around the expected ability of the utility to recover its costs of providing utility service. These factors could also include other situations such as periods of heavy capital investment, especially if such investment has a long lead time and the utility must debt fund capital expenditures (construction work in process) without receiving incremental cash flows during the construction period and/or until a future rate case to offset the additional debt. Adding debt without adding incremental cash flow has negative and harmful effects on the financial metrics discussed above. These are challenges that AmerenIP is facing today. Resp. Ex. 14.0, pp. 7-8.

Another result of having lower ratings would be an increase in borrowing costs. Investors/lenders will demand higher interest rates for providing debt capital to a lower rated credit. Resp. Ex. 14.0, p. 8.

Mr. Bodmer contends the ICC should encourage distribution companies to take advantage of high debt capacity given their very low business risk. There is much that is problematic about that recommendation. It is by no means clear that Ameren's three Illinois distribution utilities have "high debt capacity." Their senior secured debt ratings are now uncomfortably close to sub-investment grade, as discussed in Section III.E. Adding debt without adding incremental cash flow would only negatively pressure these ratings further. This situation is indicative of these utilities having an *absence* of high debt capacity. Resp. Ex. 14.0, pp. 8-9.

Moreover, Ameren's credit agreements have leverage covenants which limit the amount of debt that can be incurred by Ameren's Illinois utilities. Violation of this covenant would result in an event of default and would prevent these borrowers from utilizing the facility – a very important resource for external short-term liquidity. Resp. Ex. 14.0, p. 9.

Also, these utilities do not have "very low" business risk. S&P assigns a business profile score of "4" to each of AmerenCIPS and AmerenIP. This is a numerical score on a scale of "1" (excellent) to "10" (vulnerable) representing S&P's assessment of utilities' qualitative business or operating characteristics and risk including such factors as markets and service area economy, competitive position, fuel and power supply, operations, regulation and management. A business profile score of "1" represents an entity of lower risk than one with a business profile score of "10". Of the 33 transmission and distribution utilities referenced above, all have business profile score of "1", "2" or "3". None is rated as "4". Apparently, S&P does not believe that AmerenCIPS and AmerenIP have "very low" business risk. AmerenCILCO's S&P business profile score is "6." Resp. Ex. 14.0, p. 9.

Mr. Bodmer is essentially saying that Ameren's Illinois utilities should have much more debt in their capital structures and Ameren should just "lever up" these utilities. Not only would this be inconsistent with Ameren's commitment to maintaining the credit quality of these utilities, this would in fact be a credit hostile action. The rating agencies' reaction to this would go well beyond a simple reassessment of the resulting impact on the utilities' financial measures. This would also have a major negative impact on qualitative factors which are just as important in the ratings process. Management's credibility and commitment to credit quality would be seriously questioned. Resp. Ex. 14.0 p. 10.

The fallout from this would be significant. Ratings almost certainly would decline, borrowing costs would increase, reliable access to capital would be diminished, the ability to reliably and cost-effectively fund utility infrastructure would be harmed, the risk of financial default would increase, and investor confidence would be impaired. These consequences would be incompatible with the utilities' commitment to reliably provide utility service over the long-term. Resp. Ex. 14.0, p. 10.

Mr. Bodmer's recommendation to lever up Ameren's Illinois utilities and maintain debt ratios of at least 60% would be especially inappropriate for AmerenIP. Following Mr. Bodmer's recommendation would effectively "undo" and render moot all of those efforts and represent possibly an unprecedented (especially if the time parameter is considered) unwinding of a recapitalization strategy, raising and deployment of equity capital, and shift in wealth between classes of investors. Ameren infused $865 million of equity (which Ameren raised specifically for that purpose) in the form of cash into AmerenIP which was used to reduce debt. Premiums of about $100 million paid to bondholders were necessary to reduce that debt. These actions were consistent with achieving the conditions imposed on the Commission's approval of Ameren's acquisition of Illinois Power Company in Docket No. 04-0428. It is not appropriate that Ameren and AmerenIP should be punished for complying with the Commission's Order in that Docket in this regard, especially given Ameren's actions led to the achievement of the positive results that Ameren contemplated: the restoration of investment grade ratings, improved access to capital (including regaining access to short-term working capital) and a resulting equity ratio in the range of 50-60%. Resp. Ex. 14.0, p. 11.

AmerenIP's equity ratio is a result of Ameren's recapitalization efforts for this utility. Notwithstanding this equity ratio, AmerenIP's ratings are only marginally above the minimum investment grade rating level (the rating agencies would have course considered AmerenIP's equity ratio as part of their overall assessment and assignment of ratings). Reducing this equity ratio would imply a trade of debt capital for equity capital resulting in a net increase of debt. An increase in debt would also translate into an increase in total interest obligations. All leading to negative pressure on ratings given the decline in key financial metrics. Unless it can be demonstrated that AmerenIP's ratings are unreasonably high, it would be inappropriate to argue that its equity ratio is too high. Resp. Ex. 14.0, p. 12.

Mr. Gorman recommends that the Commission impute a capital structure at AmerenIP. In support of his postion, he argues that because S&P views the credit risk of, and rates AmerenIP based on the consolidated credit risk of Ameren and its subsidiaries, the capital structure of AmerenIP should be reasonably consistent with the capital structures of Ameren's other utilities.

First, the Ameren Companies noted that S&P is unique in its consolidated ratings approach. Neither Moody's nor Fitch utilizes this approach, instead relying on a more conventional stand-alone, legal entity-based approach. Moody's and Fitch recognize that Ameren's utilities are separate legal entities, are capitalized independently of one another (and in fact, are affiliated only because of Ameren's merger and acquisition efforts), do not share or jointly participate in the issuance and investment of permanent capital, and importantly, are not obligated for the obligations of one another. The fact that they are affiliated does not directly influence their capital structures. In fact, AmerenIP has only been affiliated with Ameren's other utilities since September 30, 2004. Resp. Ex. 14.0, pp. 12-13.

Second, "consolidated" does not mean "the same or similar." It means "added together." Ameren could have utilities engaged in interstate natural gas transportation, water, telephone, etc. and still be subject to S&P's consolidated rating approach. Resp. Ex. 14.0, p. 13.

Third, although Ameren's Illinois utilities are exposed to a number of similar business risks, they are and remain separate legal entities with separate operations, separate cash flow profiles and separate debt and preferred stock obligations. Their respective capital structures reflect these factors and related ratings effects. AmerenIP's permanent capital cannot finance the operations of its affiliates and vice versa. The Cities witness Richard W. Cuthbert acknowledges this in his direct testimony where he states, "Each Ameren subsidiary has separate operations and financial structures, with separate debt, preferred equity, and common equity of each company's capitalization." Also, AmerenIP's capital structure is in part a result of certain adjustments made by S&P including imputed indebtedness and interest obligations associated with AmerenIP's purchased power obligations. Resp. Ex. 14.0, p. 13.

Fourth, Mr. Gorman's recommendation is at odds with a fundamental cost of service ratemaking principal of ignoring the costs and effects of affiliates as part of setting rates for a given utility. Resp. Ex. 14.0, p. 13.

For all the foregoing reasons, the CUB and IIEC proposals to impute capital structures are rejected.

3. CILCO $4.64 Preferred Stock Expense

Mr. Pregozen stated that because he could not locate documentation related to AmerenCILCO's $4.64 Series issuance expenses, he could not recommend inclusion in the Company's Embedded Cost of Preferred Stock calculation. Mr. Pregozen argued that 'sometimes Staff inadvertently overlooks an adjustment due to circumstances beyond its control' as his basis for not including the expense in this case.

The Commission notes that both Company and Staff witnesses included this expense item in the Company's most recent DST case (Docket Nos. 01-0465/01-0530/01-0637 (Cons.)) and gas case (Docket No. 02-0837) without disagreement and the item was embedded in the Commission's final order. The Commission sees no reason to reach a different result here.

B. Measurement Date of Short-term and Variable Interest Rates

Moving forward the measurement period of the calculation of short-term debt negated the need for the pro forma adjustment relating to the September 2004 $75 million equity infusion at AmerenCILCO. However, given that the calculation of short-term debt at AmerenCILCO involves an average of the net short-term debt balances over the twelve months ended December 31, 2005, a pro forma adjustment for the May 2005 equity infusion of $100 million remains a necessity. The Ameren Companies contend that Mr. Pregozen erred by not making this adjustment for the months of January, February, March and April of 2005. The AmerenCILCO cost of short-term debt schedule, shown in Resp. Exhibit 15.4, correctly accounts for this adjustment. By accounting for this equity infusion, the correct balance of net short-term debt at AmerenCILCO is reflected during those four months and results in a proper LTM average short-term balance. Resp. Ex. 15.1, p. 6.

Mr. Pregozen argued in his rebuttal testimony that he 'generally opposes moving the dates for measuring the components of the cost of capital forward in time during the rebuttal phase of rate proceedings'. Recent Staff practice has shown otherwise, evidenced by Staff witness Michael McNally's update of interest rates in his rebuttal testimony in the AmerenCIPS and AmerenUE gas cases (Docket Nos. 02-0798/03-0008/03-0009 (cons.)). Resp. Ex. 35.0, p. 2. Mr. McNally used updated (May 21, 2003) spot rates for AmerenUE variable auction rate pollution control bonds for his *rebuttal* testimony dated June 5, 2003. The long-term capital structure components in this case were measured as of June 30, 2002. The Commission's order adopted Mr. McNally's position by including these updated (as of May 21, 2003) rates in their final order. *Id.* Mr. McNally also cited Docket No. 99-0534 (a Mid American Energy Company gas rate proceeding) in his testimony which addressed this issue. The following is an excerpt from the order in this Mid American case:

> Staff asserts that the Commission has consistently used the most recent market spot rate or a forecasted rate to determine the cost of short-term debt and variable rate long-term debt. Staff cites the following cases: Order, Docket No. 86-0310, Medina Utilities Corporation, April 15, 1987, p. 9; Order, Docket No. 86-0342, Lake Holiday Utilities Corporation, April 15, 1987, pp.11-12; Order, Docket No. 86-0480, Galena Territory Utilities, Inc., September 2, 1987, p. 12; Order, Docket No. 92-0116, Illinois-American Water Company, February 9, 1993, p. 62; Order, Docket No. 93-0252, Central Telephone Company of Illinois, May 4, 1994, p. 33; Order, Docket No. 94- 0065, Commonwealth Edison

> Company, January 9, 1995, p. 95; Order, Docket No. 95-0219, Northern Illinois Gas Company, April 3, 1996, p. 39.

The Commission's conclusion in its order stated 'Based on the above arguments, it is clear that the cost of short-term and variable rate long-term debt should be measured using current interest rates… These current rates are, in the Commission's opinion, the best estimates of future rates.'

Although Mr. Pregozen did not agree with updating the short-term interest rates and variable rate pollution control bond interest rates to mid-May 2006, he moved the measurement dates for the variable interest rates to April 4, 2006 to coincide with both the measurement date for the short-term interest rates that he used in his direct testimony as well as the date that Staff witness Ms. Freetly measured the equity market rate of return to revise her cost of equity in her rebuttal testimony. However, Mr. Pregozen offers no precedent or filing instructions to suggest that all cost components of capital structure need to be measured as of the same date. Mr. McNally, in the AmerenCIPS and AmerenUE case cited above, did not update his cost of equity recommendation when he updated variable and short-term interest rates. Resp. Ex. 35.0, p. 3.

Another issue with Mr. Pregozen's variable rate and short-term interest rate measurement date of April 4, 2006, was that it was conveniently placed just before significant increases in the rates of the variable rate pollution control debt. On April 17th, 18th and 21st AmerenIP's auction series 1997 A, B, and C increased 60.5, 35 and 50 basis points, respectively. On April 17th, AmerenIP's auction series 2001A (non-AMT) increased 35 basis points while AmerenIP's 2001AMT auction series 2001 AMT increased 30 basis points. On April 19th, CIPS auction series 2004 increased 25 basis points while the CILCO auction series 2004 increased 34 basis points. These significant increases in the cost of the variable rate pollution control bonds which happened nearly three months ago cannot be ignored. The interest rate environment today is very much different today than it was on April 4th. Since this date three month Libor, a key short-term interest rate, has increased about 48 basis points. Also since April 4th, the Federal Reserve has increased the Fed funds target rate twice for a total of 50 basis points amid elevated inflation worries. Further, Fed funds futures market as of Friday, July 7th was pricing better than a two-thirds chance (67%) for another Federal Reserve Fed funds rate increase at their August 8th meeting. So not only have rates risen significantly higher over the past three months, there is a good chance that rates are going to increase further. Resp. Ex. 35.0, pp. 3-4.

Mr. Gorman recommends that a recent 6-month average should be used for the variable rate pollution control bonds and short-term debt rather than the interest rate for these securities on any one specific date. Mr. Gorman's recommendation has been rejected by the Commission on several occasions. The arguments and case precedence cited earlier in favor of current spot rates obviously run counter to Mr. Gorman's proposal. In fact, the Commision's order in the AmerenCIPS and AmerenUE gas cases (Docket Nos. 02-0798/03-0008/03-0009 (cons.) left no doubt on how it views situations such as this when it made its ruling amid a historically low interest rate environment:

> The Commission agrees with Staff that there has not been a showing that historical interest rates are more representative of future interest rates than is the most recent spot rate. Moreover, even it was true that interest rates tend to follow some sort of cyclical pattern there is no evidence that they are mean reverting. As Staff suggests, in recent years the Commission has routinely rejected the use of historical average interest rates in favor of current interest rates when establishing the cost rate for variable rate long-term debt. The Commission is of the opinion that mere existence of relatively low interest rates is not a sufficient basis to use an average of historical interest rates to establish the cost for variable rate long-term debt.
>
> …Consistent with its decisions in recent rate cases where this issue has been addressed, the Commission finds that current interest rates are superior to historical averages for establishing the cost of variable rate long-term debt.

Resp. Ex. 35.0, pp. 4-5.

Mr. Pregozen argued against AmerenCILCO's $100 million pro-forma adjustment to the short-term debt balances of January through April 2005 to account for a May 2005 equity infusion, claiming that it pretends that the Company refinanced $100 million of short-term debt with common equity before January 1, 2005, although the refinancing did not occur until May 2005.

The pro-forma adjustment was made to four months of data, January 2005 through April 2005, recognizing that without the adjustment the last twelve month average short-term debt balance would be misleading and overstated. The equity infusion that occurred in May 2005 was used to permanently finance the short-term debt balance at AmerenCILCO. The adjustment was made to account for a known and measurable transaction and was both necessary and prudent to arrive at a proper last twelve-month level of short-term debt at AmerenCILCO. Resp. Ex. 35.0, p. 5.

First, Mr. Pregozen's claim that he did not have sufficient time to verify the accuracy of the adjustments and thus AmerenIP's capital structure components should not be measured as of December 2005 is far from convincing enough to disregard this data. The Staff had more than a month to prepare rebuttal testimony. Additionally, the Company has made employees available to Staff to answer questions and explain Company filings and in fact conducted a call with Mr. Pregozen on March 10th to explain the AmerenIP purchase accounting adjustments. Further, the purchase accounting adjustments detailed in earlier testimony in this case were not finalized at December 31, 2004, just three months after the acquisition was finalized. Accounting rules dictate that these adjustments can identified, calculated and adjusted up to twelve months after closing of the acquisition. Resp. Ex. 35.0, p. 6. Lastly, Mr. Cuthbert agrees with the Ameren

Companies' position. As he stated in his rebuttal testimony, he 'generally believe[s] it is best to use the actual capital structure for a recent representative period.'

Mr. Pregozen suggests that the December 31, 2004 measurement date is optimal for AmerenIP but not optimal for either AmerenCIPS or AmerenCILCO and believes that the capital structure measurement date for AmerenCIPS and AmerenCILCO should have absolutely no bearing on the measurement date for AmerenIP. He claims that AmerenIP's capital structure need not be measured at the same point in time as AmerenCIPS and AmerenCILCO any more than at the same point in time as Commonwealth Edison. While AmerenIP, AmerenCIPS and AmerenCILCO are separate legal entities and have their own capital structures, there are good reasons to have consistent dates. First, unlike Commonwealth Edison, AmerenIP along with AmerenCIPS and AmerenCILCO are under a single consolidated docket having filed cases on the same date and share the same test year. Under these circumstances, there needs to be a compelling reason why the three utilities *would not* have consistent measurement dates. The Companies agreed with Mr. Pregozen's recommendation to move forward the capital structure measurement dates for AmerenCIPS and AmerenCILCO in lieu of pro-forma adjustments. Similarly, AmerenIP's capital structure measurement date should be moved forward to account fully for the updated acquisition related purchase accounting items. And in all three of the companies' cases, the more recent data makes for a more relevant and representative capital structure -- vitally important in that will be used as a basis for future rates. Resp. Ex. 35.0, pp. 6-7.

Accordingly, the adjustments are rejected.

C. Cost of Illinois Power TFTNs

Mr. Pregozen suggests that the AmerenIP Transitional Funding Trust Notes ("TFTN") coupon rate should not be calculated using a monthly compounded methodology. Mr. Pregozen argues that by compounding monthly, the Ameren Companies overstate the cost of AmerenIP's TFTNs. He supports his claim by comparing the TFTNs to "most bonds" while ignoring the fact that they are far different from most bonds. Mr. Pregozen's argument to annualize the monthly discount rate by multiplying the rate by twelve assumes that the IFC collections are remitted by AmerenIP to the indenture trustee on a monthly basis, which is not true in this case. In fact, AmerenIP remits funds to the trustee on a daily basis, and those funds are unavailable to the company once remitted. The trustee makes interest and principal payments to bondholders quarterly, but this is irrelevant to AmerenIP's cost of debt. Resp. Ex. 15.1. Accordingly, Staff's position is rejected.

D. Cost of Equity

The Ameren Companies proposed a return on equity of 11%. The Ameren Companies presented the testimony of Kathleen McShane, a cost of capital expert employed by Foster Associates, Inc. Ms. McShane performed a discounted cash flow ("DCF") test, an equity risk premium, or CAPM, test and a comparable earnings test. The midpoint of her recommendations exceeded 11%, but the Ameren Companies decided to take the low end of her range, in order to mitigate the effect of the rate increase on all customer classes. Resp. Ex. 1.0, p. 3.

Ms. McShane's analysis and recommendations, took into account several considerations (Resp. Ex. 3.0, pp. 3-6). She testified that the estimation of a fair return on equity starts with a recognition of the objective of regulation. That objective is to simulate competition, i.e., to establish a regulatory framework that will mimic the competitive model. Under the competitive model, the required return on equity is expected to reflect the opportunity cost of capital, i.e., a return that is commensurate with the returns available on foregone investments of similar risk. Resp. Ex. 3.0, pp. 6-7.

Ms. McShane testified that the objective of regulation, in conjunction with a utility's obligation to serve, has given rise to multiple criteria for a fair and reasonable return. A fair return is one that provides a utility with the opportunity to:

(1) earn a return on investment commensurate with that of comparable risk enterprises;

(2) maintain its financial integrity; and,

(3) attract capital on reasonable terms.

The ability to attract capital is not synonymous with being allowed a return comparable with those of similar risk entities. A return that simply allows a utility to attract capital, irrespective of the cost, does not lead to the conclusion that it is compatible with the comparable returns standard. Resp. Ex. 3.0, p. 7.

The determination of the return on common equity for regulated companies has traditionally been a "hybrid" concept. The cost of equity is a forward-looking measure of the equity investors' required return. It is, therefore, an incremental cost concept. The required equity return is not, however, applied to a similarly determined rate base (that is, current cost). It is applied to an original cost rate base. When there is a significant difference between the historic original cost rate base and the corresponding current cost of the investment, application of a current cost of attracting capital to an original cost rate base produces an earnings stream that is significantly lower than that which is implied by the application of that same cost rate to market value. The divergence between the earnings stream implied by the application of the return to book value rather than market value is magnified as a result of the long lives of utility assets. Resp. Ex. 3.0, p. 10.

Ms. McShane applied the discounted cash flow model, equity risk premium tests (including the capital asset pricing model), and the comparable earnings test. In arriving at her recommendation, she gave primary weight to the market-based tests, that is, the discounted cash flow and equity risk premium tests. The comparable earnings test was used as a test of the reasonableness of the DCF and ERP results. Reliance on multiple tests recognizes that no one test produces a definitive estimate of the fair return.[3] Each test is a forward-looking estimate of investors' equity return requirements. However, the premises of each of the three tests differ; each test has its own strengths and weaknesses. In principle, the concept of a fair and reasonable return does not reduce to a simple mathematical construct. It would be unreasonable to view it as such. Resp. Ex. 3.0, p. 12.

In applying the DCF test, the objective is to set the return component of the delivery service tariffs. Thus, in principle, the return should reflect the stand-alone principle, that is, the cost of capital for delivery service, which is a "wires" function. Most of the publicly-traded electric utilities operate not only the "wires" business, but also have generation assets. These utilities would not be appropriate proxies for the Ameren delivery service. It is not possible to select an adequate sample of "wires-only" electric utilities, i.e., companies which are predominantly transmission and distribution utilities. Therefore, she applied the discounted cash flow test to a sample of 12 local gas distribution utilities (LDCs) that serve as a proxy for the delivery operations of the Ameren Companies. Resp. Ex. 3.0, p. 14.

Delivery service, which is part of the "wires" operations of an electric utility, is functionally similar to natural gas distribution. The key difference between electric delivery service and gas distribution is that most gas distributors continue to both sell and deliver natural gas. Delivery service, however, represents solely the "transportation" of power that customers

[3] As stated in Bonbright, "No single or group test or technique is conclusive." (James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, 2nd Ed., Arlington, Va.: Public Utilities Reports, Inc., March 1988).

have purchased either from a Retail Energy Supplier or from the incumbent utility through the Power Purchase Option. Nevertheless, gas distributors are permitted to pass through to customers the differences between actual and forecast gas costs, subject to prudency. Thus, the risk that they will not fully recover commodity costs is very limited. As a result, the business risks associated with the "wires" operations of an electric utility are more analogous to those of gas distribution than to the business risks faced by the majority of publicly-traded electric utilities, whose consolidated operations include generation, both regulated and unregulated. Resp. Ex. 3.0, pp. 14-15.

There is a critical caveat to that conclusion. The application of the LDCs' equity return requirement to the Ameren Illinois Utilities is premised on a "typical" level of regulatory risk. "Typical" in this context means that the regulatory environment is sufficiently stable and predictable to assure the investor that the utility has a reasonable opportunity to recover all prudently incurred costs on a timely basis, including a fair return on investment. There is significant concern presently that Illinois does not offer such an environment, as evidenced by recent comments and debt rating actions by S&P, Moody's and Fitch for the Ameren utilities, as well as for other Illinois utilities (e.g., Commonwealth Edison). These comments and actions have been driven expressly by recent political intervention in the regulatory process, which creates uncertainty for investors. Ms. McShane's return recommendations explicitly exclude consideration of any regulatory uncertainty that may exist in Illinois as a result of the recent politicization of the regulatory environment. Were recent actions and statements by some Illinois state officials and their impact on regulatory risk to be factored into the analysis of the equity return requirement, the cost of equity and the recommended allowed return would be significantly higher. Resp. Ex. 3.0, p. 15.

The sample includes every LDC:

(1) classified by *Value Line* as a gas distribution utility;

(2) with no less than 80% of total assets devoted to gas distribution operations; and,

(3) whose Standard & Poor's debt rating is BBB- or higher.

Ms. McShane used the Capital Asset Pricing Model ("CAPM") and two direct estimates of utility equity risk premiums, the first by reference to historic achieved equity risk premiums for LDCs and the second by reference to forward-looking equity risk premium estimates for LDCs.

The CAPM relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth). Company-specific risks, according to the CAPM, can be diversified away by investing in a portfolio of securities, and therefore the shareholder requires no compensation to bear those risks. Resp. Ex. 3.0, p. 35.

In simplistic terms, the CAPM requires determining the equity risk premium required for the market as a whole ("market risk premium"), then adjusting it to account for the risk of the particular security or portfolio of securities using the beta. The result (market risk premium multiplied by beta) is an estimate of the equity risk premium specific to the particular security or portfolio of securities. Resp. Ex. 3.0, p. 36.

She utilized the forecast yield on the 10-year Treasury bond as a proxy for the risk-free rate. In principle, a longer-term Treasury should be used, so as to more closely match the duration of the risk-free rate and common equities. However, in 2001 the U.S. Treasury stopped issuing new 30-year bonds. As a result, the yield on existing 30-year Treasuries became a less reliable proxy for the risk free rate. Although the Treasury has announced its intention to once again issue new 30-year debt commencing February 2006, the 10-year Treasury bond remains the benchmark, and is likely to remain so. As a result, her CAPM analysis relies on the benchmark 10-year Treasury yield as the risk-free rate proxy. Resp. Ex. 3.0, p. 37.

Ms. McShane concluded that a fair return is in the range of approximately 11.5-13.0%, where the lower end represents a minimum adjustment for financing flexibility and the upper end of the range represents an adjustment to the market-derived cost of equity to recognize a long-run equilibrium market/book ratio of 1.50. Resp. Ex. 3.0, pp. 37-51.

She also explained that the comparable earnings test provides a measure of the fair return based on the concept of opportunity cost. Specifically, the test is derived from the premise that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. Since regulation is intended to be a surrogate for competition, the opportunity cost principle entails permitting utilities the opportunity to earn a return commensurate with the levels achievable by competitive firms of similar risk. The comparable earnings test, which measures returns in relation to book value, is the only test that can be directly applied to the equity component of an original cost rate base without an adjustment to correct for the discrepancy between book values and current market values. Resp. Ex. 3.0, pp. 51-52.

The concept that regulation is a surrogate for competition implies that the regulatory application of a fair return to an original cost rate base should result in a value to investors commensurate with that of similar risk competitive ventures. The fact that a return is applied to an original cost rate base does not mean that the original cost of the assets is the appropriate measure of their fair market value. The comparable earnings standard, as well as the principle of fairness, suggests that, if competitive industrial firms of similar risk are able to maintain the value of their assets considerably above book value, the return allowed to utilities should likewise not foreclose them from maintaining the value of their assets as reflected in current stock prices. Resp. Ex. 3.0, p. 52.

At the very least, the results of the comparable earnings test should be relied upon as an indicator of whether the market-based test results, as adjusted for the market/book ratio are reasonable. The DCF test and equity risk premium tests as adjusted for a long-run equilibrium market/book ratio of 1.50 indicate returns in the range of 12.0-13.0%. The risk-adjusted comparable earnings test indicates that low risk competitive firms are able to earn returns in a very similar range, 12.75-13.25%. Resp. Ex. 3.0, p. 58.

Staff witness Freetly takes issue with Ms. McShane's conclusions that the recent forecasted three- to five-year growth rates for utilities are low relative to expected long-term growth in the economy as a whole and likely to understate the growth rates that investors expect into perpetuity (that is, the growth rate that is reflected in the stock price). In that regard, she states that past growth rates may be misleading, since they may reflect changes in the fundamental variables that investors do not expect to continue in the future, or fail to capture changes that investors do expect. The Ameren Companies do not disagree that historical actual growth rates may be misleading as estimates of what investors expect going forward. Resp. Ex. 33.0, p. 2. Ms. MsShane's comments with respect to the level of expected growth for the next three to five years, however, were in reference to the level of growth that analysts had *forecast* for similar periods during the past 13 years (1993-2005). The point she was making was that, on average, the three- to five-year growth rates had varied around a rate approximately equal to the expected growth in the economy as a whole. *Id.* Thus, while investors may expect growth for utilities in the relatively short-term to be lower than growth in the economy, the observed pattern of expected three- to five-year growth rates strongly suggests the expected growth rate in perpetuity mirrors the rate of growth in the economy. Changes in variables such as regulation may alter short-term growth expectations, but in the absence of a major shift in economic fundamentals (e.g., inflation, productivity), the long-term inherent growth potential for utilities should remain relatively stable. *Id.*

Ms. Freetly also contended that the long-term expected growth for utilities must be lower than the growth in the economy as utilities are of lower than average risk, earn lower than average returns, and have below average retention rates. It is clear from Ms. Freetly's own evidence, however, that, at the present time, the expected growth rate for the average stock is well in excess of the rate of growth in the economy. Resp. Ex. 33.0, p. 2. Ms. Freetly stated that the average expected rate of growth for dividend paying stocks in the S&P 500 is 11.3%, or more than twice the expected growth in the economy. ICC Staff Ex. 15.0. If utilities were excluded from the S&P 500 index, the expected growth rate for the remaining dividend paying sectors would be higher than 11.3%. Resp. Ex. 33.0, p. 3. That comparison simply confirms that utilities are expected to grow more slowly than the average stock in the next three to five years, but provides no basis for concluding that the expected growth for utilities in perpetuity should be less than the rate of economic growth. *Id.*

Ms. Freetly also states that the market efficiently reflects growth expectations in the stock price and that those expectations need to be reflected in the DCF model whether they are irrationally exuberant or irrationally pessimistic. The question is whether the irrational exuberance or pessimism is for the near-term or the long-term. Resp. Ex. 33.0, p. 3. Since we cannot read investors' minds, we cannot state with any degree of certainty whether the stock price today incorporates the expectation that the three- to five-year growth rate forecasts will continue forever, or the expectation that growth will trend over time to a long-run value. Consequently, estimating the utility cost of equity using both assumptions is a reasonable means of approximating long-term growth expectations. *Id.*

Ms. Freetly claims that Ms. McShane's comparison of Staff's DCF estimate to utility bond yields as a means of testing its reasonableness is misleading on two counts; first because she is not recommending a return equal to the 9.11% DCF cost, and second, because a comparison with Baa rated utility bond yields is not appropriate since she is recommending returns that, in her view, are compatible with the achievement of debt ratings higher than Baa. Ms. McShane's conclusions in this regard were in specific reference to the results of Staff's DCF test, given the growth rates Ms. Freetly had used, and to whether the results of that specific test were reasonable in light of historic relationships between allowed returns and yields on utility bonds in the same rating category as her sample (median S&P debt rating of BBB+). In this context, the allowed returns were used as a proxy for the DCF cost, on the grounds that the DCF test has historically been the principal test used by state regulators in setting allowed ROEs. Resp. Ex. 33.0, p. 4.

Ms. Freetly claims that there is nothing inherently superior about the *Value Line* betas as compared to her regression betas, and states that, in contrast to earlier time periods, when her raw regression beta was unusually low, her current raw beta is more typical. The term "typical," however, assumes that the "true" beta is static. Exhibit 33.0, Schedule 1 demonstrates that the *Value Line* betas for Ms. Freetly's sample have been rising over time.[4] The betas are considerably higher for the most recent period available (median of 0.90) than the 0.75 level observed prior to the anomalous market bubble and bust period (1998-2002) during which utility

[4] Exhibit 33.0, Schedule 1 provides a history of the *Value Line* betas of Ms. Freetly's sample.

betas were unusually low. The rising betas of these utilities demonstrate that the accuracy of Ms. Freetly's regression betas cannot be tested against what has been "typical". The fact remains that calculating betas using more observations (i.e., *Value Line*'s weekly observations versus Ms. Freetly's monthly observations) will improve the fit of the regression line. Resp. Ex. 33.0, pp. 4-5.

Mr. Gorman makes a similar argument to that of Ms. Freetly regarding the growth prospects of utilities relative to the S&P 500. He simply shows that the growth for companies that pay out more in dividends than those that do not would be expected to achieve lower growth rates in the near future than those that retain more. We have no disagreement with this basic proposition. Ms. McShane has not claimed, as Mr. Gorman suggests, that utilities can grow as fast the growth rates currently anticipated for the S&P 500. Over the next three to five years, the expected growth rates for the companies in the S&P 500, who are currently paying out about 30% of earnings, are much higher than the expected growth in the economy, as indicated in Ms. Freetly's testimony. Consistent with the higher expected growth is a much lower dividend yield for the S&P 500 than for utilities. When the growth prospects for the companies that currently make up the S&P 500 decline (and gradually trend toward the growth in the economy and potentially lower when they reach the stage of decline), they will begin to pay out a higher proportion of their earnings in dividends and exhibit higher dividend yields. There is no inconsistency between that proposition and the expectation that long-run growth prospects of the mature utility industries mirror the long-run growth potential in the economy as a whole. Resp. Ex. 33.0, pp. 6-7.

Mr. Gorman takes issue with a critique of his risk premium test in which he estimates the annual average differential between allowed returns and bond yields over the period 1986-2005 rather than a more recent period, on the grounds that inflation impacts both stock and bond yields and valuations.

Ms. McShane agreed that inflation impacts both. The issue is whether the fear of inflation impacts both equally. If inflation rises above expected levels, bond investors will be impacted more negatively, since they are locked-in at the rate at which they invested. If there is a strong fear of unanticipated inflation, bond investors will require an additional premium above the expected rate of inflation (a lock-in premium). Since equities are a better hedge against unanticipated inflation, equity investors will not demand a lock-in premium of the same magnitude. During periods when the fear of unanticipated inflation is high, and the lock-premium in bond yields is also high, the equity risk premium will be lower. When the fear of unanticipated inflation dissipates, the equity risk premium will expand. Resp. Ex. 33.0, pp. 7-8.

The existence of a higher lock-in premium during the earlier years of Mr. Gorman's analysis can be discerned by comparing real dividend yields and real bond yields from 1986-1995 and from 1996-2005. During 1986-1995, the average real utility dividend yield was 3.1% compared to the real Treasury bond yield of 4.0%, where the real yield was estimated as the nominal yield in each year minus the forecast long-term rate of CPI inflation.[5] By comparison, during 1996-2005, the real utility dividend yield had not declined at all from its average 1986-1995 level, while the real Treasury bond yield had declined by .9% to 3.1% (Exhibit 33.0, Schedule 3). The larger decline in the real bond yield is a strong indicator of a reduction in the relative risk of Treasury bonds and an increase in the equity risk premium. Using the longer 1986-2005 period to measure the differential between allowed returns and bond yields masks the

[5] From *Blue Chip Economic Indicators'* bi-annual long-term forecasts during the year that corresponds to the actual bond and utility dividend yields as presented in MPG-R1. See Exhibit 33.0, Schedule 3.

change in the equity risk premium that occurred as bond investors became increasingly comfortable that inflation would not reignite to levels that had been experienced in the 1970s and early to mid-1980s. Resp. Ex. 33.0, p. 8.

Mr. Cuthbert argued that Ms. McShane's results are overstated because you did not conduct any risk premium analyses relative to corporate bond yields. Mr. Cuthbert conducted one test using corporate bond yields. The result was higher than his DCF results and lower than his CAPM results. The simple average of his DCF, equity risk premium and CAPM results for his comparable sample as summarized on RWC-6 is 9.7%. Excluding the risk premium test using corporate bond yields, the simple average of the DCF and CAPM tests is lower, at 9.65%. Based on Mr. Cuthbert's own tests, ignoring any problems with their application, there is no basis to conclude that including a test using corporate bond yields would produce a lower recommended return. Resp. Ex. 33.0, p. 15.

Mr. Bodmer claims that Ms. McShane's real argument is that this Commission should grant the Ameren utilities a similar return to that which has been allowed by other state commissions. It goes without saying that the estimation of the cost of equity and a fair return should be independent of what other regulators allow. Nevertheless, the national average can be interpreted as a consensus assessment of the expert testimony that has been proffered by a wide range of stakeholders under capital market conditions that are similar to those prevailing. As one regulatory commission correctly observed in a recent decision approving an 11.0% ROE, a return on equity finding should not mindlessly mirror the national average. However, the regulatory commission also pointed out that the national average is an indicator of the capital market in which the utility will have to compete for necessary capital. Similarly, the national average is an indicator of the reasonableness of the return recommended. It is not necessary to address each aspect of Mr. Bodmer's testimony to conclude that his recommended return of "no greater than 8%" simply is not indicative of the capital market in which the Ameren utilities will have to compete for capital. Resp. Ex. 33.0, p. 16.

Mr. Bodmer also claims that the high market/book ratios of utilities are an indication that the allowed returns should be lower than they are. Mr. Bodmer believes that the market/book ratio of utilities should be 1.0. There are multiple reasons this would not be the case even if such an outcome were fair and reasonable.[6] These reasons include the fact that market price reflects future earnings expectations, expected earnings from unregulated operations, the fact that the reported assets are an imperfect measure of the base upon which utilities are allowed to earn a return, and the value that investors place on the stability of dividends. Moreover, the level of the market/book ratios of utilities is a relative concept, and should be judged relative to the tenor of the market as a whole. Over the past 10 years (1996-2005), the market/book ratio of the S&P 500 has averaged 3.6 times; it is currently 3.0 times (*Barron's*, June 26, 2006). Over the same decade, the market/book ratio of all the utilities that are included in the proxy samples of Ms. Freetly, Mr. Gorman, Mr. Cuthbert and myself averaged 1.6 times, less than half the level of the equity market composite (which includes utilities); the current median market/book ratio for these same utilities is also 1.6 times; See Exhibit 33.0, Schedule 5. Relative to the market as a whole, the market/book ratios of the utilities are quite modest and provide no basis for concluding that allowed returns have been too high. Resp. Ex. 33.0, p. 17.

Mr. Cuthbert claims that Ms. McShane's sample of gas distribution utilities is of higher risk than a sample of electric utilities. To support his view that gas utilities are more risky than

[6] See Exhibit 3.0, lines 538-545 for discussion of why a market/book ratio of 1.0 for a utility is inconsistent in principle with the competitive model that regulation is intended to emulate.

electric utilities, Mr. Cuthbert cites a *Value Line* article (RWC-7) which refers to the impact of rising gas prices on gas utilities. Mr. Cuthbert implies that the article concludes gas utilities are more risky than electric utilities, which it does not. One risk factor cannot be used to conclude that gas utilities are more risky than electric utilities. The various risk statistics of Mr. Cuthbert's and my samples demonstrate objectively and quantitatively that the gas utilities I have relied upon are less risky than his sample of electric utilities (Exhibit 13.0, Table 4). Mr. Gorman also uses a sample of gas utilities; there is no objective evidence that his sample of gas distributors is riskier than his electric utility sample. Ms. Freetly includes gas utilities in her sample; there is no objective evidence that the gas distributors in the sample are riskier than the electric utilities in the sample. Resp. Ex. 33.0, p. 11.

The rcord shows that the Ameren Companies have adequately supported their propsoed return onequity and it should be adopted.

[Alternate language, if adopting Staff proposal: Staff witness Freetly recommended returns on equity of 9.9%, 9.85% and 9.96% for AmerenCILCO, AmerenCIPS and AmerenIP, respectively. She arrived at her recommendation by first estimating the investor required return for her utility sample at 10.25%. She then adjusted the result downward for each of the Ameren Companies to reflect her belief that each of the Ameren Companies is lower in risk relative to the sample. Tr. 994 (Freetly).

Ms. Freetly determined that the Ameren Companies are of lower risk by developing "implied forward looking credit ratings" for each Company and comparing those to the average credit ratings of the sample. ICC Staff Ex. 15.0, p. 6; Tr. 994-95 (Freetly). She developed those "implied ratings" by using values for certain benchmark financial ratios that result from the application of the Staff's revenue requirement. Tr. at 995 (Freetly). In other words, she factored in the presumed effect of the revenue increases recommended by the Staff in this case on the Ameren Companies' future credit ratings. Tr. at 997 (Freetly).

The Ameren Companies state, and the Commission agrees, that a principal problem with Ms. Freetly's analysis is that she assumes that the Companies will have higher credit ratings than they currently have. That is, she assumes that the Companies' credit ratings will be going up, at a time when they are going down for reasons that have nothing to do with the issues before the Commission in this case.

During the hearings, Moody's issued a release regarding the Ameren Companies' credit ratings, in which it downgraded AmerenCIPS and AmerenCILCO. Ameren Freetly Cross Ex. 1. As a result of those downgrades, AmerenCILCO's rating is four notches below the level assumed by Ms. Freetly, and AmerenCIPS is six notches below her assumed level. Tr. at 999 (Freetly). AmerenIP was unchanged, but is still four notches below Ms. Freetly's assumed level. Tr. at 1000 (Freetly).

The Ameren Companies argued that there is nothing in the record to suggest that the wide gulf between the current ratings and Ms. Freetly's assumed ratings will be bridged by the final order in this case. Moody's downgraded AmerenCIPS and AmerenCILCO, and held AmerenIP just one notch above sub-investment grade, due to "a difficult political and regulatory environment for electric utilities in the state of Illinois," related to rate increases for "purchased power costs." Ameren Freetly Cross Ex. 1. Further, Moody's indicated its expectation that "the outcome will involve a material regulatory deferral of higher procurement costs." *Id.* Hence, the Ameren Companies' ratings are moving the opposite direction of Ms. Freetly's assumption due to factors that are outside the scope of this proceeding and which the final order in this case will not and cannot address.

Moreover, even if Moody's had not downgraded the Companies, there is still no basis for Ms. Freetly's conclusions regarding the Companies' prospective ratings. Mr. Nickloy explained why Staff's recommendation improperly assumes specific credit ratings. In its 2004 publication providing revised financial guidelines for U.S. utilities (*New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised*, published June 1, 2004), S&P stated, that these financial guidelines represent three principal ratios that S&P uses as an "integral part" of evaluating the credit quality of U.S. utility and power companies. Resp. Ex. 14.0, p. 2. Thus, while these ratios are certainly important, S&P clearly indicates that these measures are only a *part* of S&P's *evaluation*. These measures do not constitute anything even close to the *entirety* of their analysis. They are used as part of an *evaluation*, i.e. an analysis or assessment, of the credit quality of the subject entity. Taken together, this means the ratios are used in the context of an overall, comprehensive credit analysis including, as we know, both quantitative factors such as these and other ratios along with a variety of qualitative factors. This does not mean that simply by achieving one or more of these ratio guidelines (especially given the leverage ratio) for a given rating level that any given rating will automatically be assigned. It also noteworthy that S&P has characterized these measures as "guidelines." *Id.* at 2-3.

It is not appropriate then to use S&P's published financial ratio guidelines as the sole basis for the reasonableness of a recommendation for a given cost of equity, weighted average cost of capital, capital structure (including any hypothetical capital structure) and/or revenue requirement, for a number of reasons:

(1) Although financial ratios are important in any evaluation of an entity's credit quality, ratios alone do not define the analysis, especially if only considering a single ratio such as leverage (debt to capital). In the S&P publication referenced above, S&P includes the following language immediately before and immediately after the table listing their ratio guidelines:

> "It is important to emphasize that these metrics are *only guidelines* associated with *expectations* for various rating levels. Although credit ratio analysis is an important part of the ratings process, these three statistics [FFO interest coverage, FFO/total debt, and debt/capital] are by no means the only critical financial measures that [S&P] uses in its analytical process." (Emphasis added.)
>
> And,
>
> "Again, *rating analysis is not driven solely by these financial ratios*, nor has it ever been. In fact, [these revised financial guidelines] reinforce the analytical framework whereby other factors can outweigh the achievement of otherwise acceptable financial ratios." (Emphasis added.)
>
> We simply cannot ignore what the rating agencies have said here – the ratio guidelines are not definitive in terms of the assignment of ratings.
>
> (2) The ratio guidelines at issue here are only those published by S&P. The S&P guidelines would not be instructive or helpful in attempting to presuppose any ratings assigned by Moody's based on a similar analysis.
>
> (3) The rating agencies are the arbiters of credit ratings. Any analysis performed by others in an attempt to support or assume a given rating can be dangerously misleading. This would be especially true given the qualitative factors which are important to the rating agencies at the time they are reviewing or assigning ratings. The specific factors, and the relative importance or weighting those factors receive in the rating agencies' analyses are known with certainty only by the agencies.
>
> (4) As part of their ratio analysis, the rating agencies typically make certain adjustments. For example, S&P and Moody's remove the debt related to AmerenIP's transitional funding trust notes ("TFNs") along with the cash flow dedicated to service that debt. S&P also imputes a debt equivalent for AmerenIP's power purchase agreement with Dynegy along with related imputed interest.

Resp. Ex. 14.0, pp. 3-4.

These adjustments can have a meaningful impact on the calculation of financial ratios. The cash flow adjustment to remove the effects of AmerenIP's TFNs results in a reduction of annual cash flow of at least $86 million. This cash flow adjustment has a meaningful negative impact on any metric that uses cash flow as an input (such as interest coverage and cash flow/debt). Mr. Nickloy explained that the Ameren Companies know from discussions with S&P that the imputed debt equivalent related to its purchased power arrangement with Dynegy (a 2.25-year arrangement at the time of the closing of Ameren's acquisition of AmerenIP) was around $600 million. S&P recognized that notwithstanding the relatively short tenor of this specific power supply agreement, AmerenIP's need to continue to obtain its power supply requirements from third parties would continue well beyond the maturity date of that agreement. Annual interest related to this debt imputation was based on an interest rate of 10%. Given the potential magnitude of these adjustments, any ratio analysis must reflect such adjustments in the same manner as performed by the rating agencies. The purchased power debt imputation issue could remain significant for AmerenIP and become a much bigger issue for AmerenCIPS and AmerenCILCO once new power supply arrangements are entered into for periods post 2006. Resp. Ex. 14.0, p. 5.

On balance, with respect to being consistent with a given rating, there certainly would be reason for concern if an entity's ratios were to decline or fall out of the S&P ratio guideline ranges for that rating. However, to reiterate, it would be unwarranted and inappropriate to assume that simply because that entity's metrics fall within the guideline ranges that the related rating will be the result. Resp. Ex. 14.0, p. 5.

Even if Ms. Freetly could accurately predict credit ratings, her adjustment would still be unfounded. The Ameren Companies agree with Ms. Freetly that, in principle, there is a direct relationship between risk and required return. However, Ms. Freetly has not demonstrated that, in practice, the DCF test is accurate enough to distinguish between samples of somewhat different levels of investment risk. Ms. Freetly made the unwarranted assumption that the DCF cost of equity that she estimated for her sample is a completely accurate measure of the cost of equity for that risk level. The implication of that assumption is that, had she actually measured the DCF cost of equity for a lower risk utility sample, e.g. a sample whose average debt rating was AA, the DCF estimates would have been lower than those of her sample by approximately 40 basis points. Ms. McShane's comparison of the DCF costs of Mr. Gorman's two samples demonstrated that is not necessarily the case, as the estimated DCF cost for his gas sample was 30 basis points higher than the DCF cost for his electric sample. The electric utility sample is at least as risky, and potentially more risky, than his gas sample.

To further illustrate this point, Ms. McShane took all the utilities that were in the utility samples of the five direct cost of capital testimonies filed in this proceeding, and calculated their DCF cost using the annual constant growth DCF model, the stock price as of April 4, 2006 (the same date used by Ms. Freetly in her DCF test), the most recent dividend paid prior to that date, and the I/B/E/S consensus forecast of earnings growth for each utility at the end of March 2006. She then sorted the utilities by their April 7, 2006 S&P bond rating. Next, she calculated the mean and median DCF costs for all of the utilities with a debt rating of BBB-, BBB, and BBB+, and the mean and median debt costs of all of the utilities with a debt rating of A-, A, or A+. The mean and median DCF costs for the utilities rated in the BBB category were 9.5% and 8.7% respectively; the mean and median DCF costs for the utilities with ratings in the A category were 9.7% and 9.1% respectively (See Exhibit 33.0, Schedule 2). In other words, the estimated DCF costs were higher for the less risky companies. Thus Ms. Freetly's deduction from her sample's DCF cost of equity for the alleged relatively lower risk of the Ameren utilities cannot be empirically justified. Resp. Ex. 33.0, p. 6.]

V. RATE DESIGN

A. Below is a Summary of the Uncontested/Settled Issues.

- The Ameren Companies accept Staff witness Greg Rockrohr's proposal in concept with regard to the prior AmerenCIPS incentive to have customers install their own transformers. The Ameren Companies will provide a separate, lower, customer charge for those customers who are metered on the primary side of customer-owned transformers, so long as the proposed test or billing units are allowed to be adjusted. (Resp. Ex. 20.0, pp.15-16). These customers will be assessed the Customer and Meter Charges as if they were metered on the lower voltage side of transformation. (Resp. Ex. 41.0, p.19). The specific steps to mitigate these charges are identified at Resp.' Exhibit 20.0, pages 16-17.

- Acceptance of Staff's proposal to adjust rates if the final revenue requirement is different than proposed, where if the difference in the Customer and Meter Charges is less than a relatively small charge of 25 cents per month for DS-1 customers, no adjustment is made; if the charge is greater than 25 cents, adjust Customer and Meter charges by combined Ameren Companies' percentage change in total revenue requirement, and the remaining revenue requirement is recovered through a percentage adjustment to various Distribution Delivery Charges applicable to the customer classes at each Ameren Company. (Resp. Ex. 41.0, p.18).

- Acceptance of Staff's proposed language to be inserted in DS-1 to ensure that existing customers receiving three-phase service will not have to pay an Excess Facilities charge. (Resp. Ex. 20.0, pp.17-18).

- Acceptance of Staff's proposed language change to Section 14.D of the Customer Terms and Conditions. (Resp. Ex. 20.0, pp.38).

- Acceptance of Staff witness Griffin's proposed changes to the Qualifying Solid Waste Energy Facility provisions of Rider QF (Resp. Ex. 20.0, p.34).

- The Ameren Companies agreed with Staff to meet certain criteria, should they implement a new or revised charge under Local Government Fee and Adjustment tariffs. These criteria include: a) notify Commission; b) receive authorization to implement; c) include proper documentation; d) include supporting calculations; and e) include a listing of fees by local government authority similar to those in Municipal Tax Additions. (Resp. Ex.31, p.12).

- Acceptance of the CNE/PES position, that the Ameren Companies provide a schedule similar to Schedule 10.10 on the Ameren website, explaining the translation of the existing schedule of rates. (Resp. Ex. 20.0, p.41).

- Acceptance of the IIEC recommendation, that the Ameren Companies provide projections of hourly system load figures at least on a day-ahead basis and to post a day-ahead forecast of hourly loss multipliers for each voltage level. This will serve to allow suppliers the opportunity to minimize settlements associated with errors in distribution loss calculations. (Resp. Ex. 41.0, pp.23-24).

- Agreement by the Ameren Companies to eliminate the DASR Submission Fee and Standard Switching Fee. (Resp. Ex. 41.0, p.25).
- Agreement to implement certain EDI transactions. (Resp. Ex. 49.0, pp.10-11).
- Agreement to include 24 months of customer billing data on Ameren.com. (Resp. Ex. 48.0, p.4).
- The Ameren Companies and the AG reached an understanding with regard to the claim that the franchise expense was being duplicated. AG witness Effron acknowledges that the Ameren Companies have adjusted their revenues to reflect what the revenue would be if free service was billed at tariff rates as explained by Ameren Company witness Jones. (See AG Ex. 3.0, pp.10-11; Resp. Ex. 20, pp.38-39).
- Revisions to Rider TS per the request of CNE/PES. (Resp. Ex. 20.0, p.29).
- Calculated Cash Working Capital factors for each of the Ameren Companies, to be reset in subsequent delivery service rate cases. (Ameren Ex. 6.0S, p.3).

B. Customer Class Issues

1. General Discussion

The Ameren Companies are proposing to use five service classifications. DS-1 is for all Residential Service; DS-2 is Small General Service for all non-residential up to 150 kW; DS-3 is General Service for all non-residential, from 150 kW up to 1,000 kW; DS-4 is Large General Service for all non-residential 1,000 kW and greater; and DS-5 is for Lighting Service. (AmerenCILCO Ex. 10.0, p.4, AmerenCIPS Ex. 10.0, p.4 and AmerenIP Ex. 10.0, p.4). No party took issue with the new classes as being proposed, except as to DS-3 as addressed below. Staff witness Cheri Harden agreed the rate classifications are appropriate as they are primarily differentiated by customer usage and voltage level at which customers are served. (ICC Staff Ex. 7.0, p.5).

2. Wal-Mart Recommendation Regarding Separate Rate Classes

Wal-Mart witness James Selecky proposed that the DS-3 class be separated into two separate rate classes, one for customers with demands ranging from 150 kW up to 400 kW and another for customers with demands of 400 kW up to 1,000 kW. Mr. Selecky's justification for the sub-classes is that the DS-3 service classification is too broad, relying upon testimony provided in the Commonwealth Edison procurement case. (Wal-Mart Ex. 1.0, p.13).

There are a number of reasons why the Wal-Mart proposal should be rejected, at least at this time. Creating a new rate class involves a study of the class load characteristics to ensure that a separate rate class is in fact warranted. Neither Mr. Selecky nor the Ameren Companies have created such a study and, indeed, Mr. Selecky relies upon information from the Commonwealth Edison proceeding. Mr. Selecky knowing full well that such a study is required, recommended the Commission require the Ameren Companies to provide the cost of service study in this case, which has not occurred. (Wal-Mart Ex. 1.0, p.14). Such a study was not provided as Wal-Mart failed to properly place the issue before the Commission.

Next, for customers with demand over 400 kW, the Ameren Companies intend to install interval metering which will be accomplished within the next two years. This metering will be helpful should there be decision to create the sub-classes. Mr. Selecky also recognizes this as a potential obstacle to creating the sub-classes. (Wal-Mart Ex. 1.0, p.14).

Mr. Jones also observed that without the benefit of further analysis or study, creating sub-classes in this proceeding would result in revenue responsibilities amongst the sub-classes that are simply unknown. (Resp. Ex. 20.0, p.4). Meaning, there could be an undue shifting of revenue responsibilities absent the appropriate data.

In conclusion, while the Ameren Companies are open to the notion of creating sub-classes as suggested by Wal-Mart, appropriate study and consideration with the requisite data and information is not yet at hand. Until such time as interval metering is in place, and the necessary data by which to ascertain the appropriateness of creating sub-classes is available, creating sub-classes at this time is premature. Therefore, there should be no mandate in this proceeding to create the sub-classes.

C. Cost of Service Issues

1. Segregation and accounting for delivery service and generation-related uncollectible expenses

The Ameren Companies proposed that the recovery of uncollectible expenses be consistent with the method as proposed by the Ameren Companies in their competitive power procurement cases. The proposal involves the establishment of an uncollectible expense factor based on the relative relationship between total uncollectible expenses to the total bundled revenue amounts. This factor is then applied to the BGS price to account for the expected level of uncollectible BGS bill amounts and to the Transmission Service expenses to account for the expected level of uncollectible Rider TS bill amounts. The Rider BGS and Rider TS billings for all customers receiving power supply from the Ameren Companies will include an amount to reflect the Ameren Companies' uncollectible experience. (See AmerenIP Ex. 8.0, pp.6-7).

Mr. Cooper explained a fair and equitable segregation of uncollectible expense can be resolved in the rate making process and noted further that both the Ameren Companies and Staff witness Ebrey had developed similar approaches, in developing the appropriate level of uncollectible expense associated with the provision of delivery services. An uncollectible "factor" is developed for each customer class, and the effect of the factor is to designate a certain amount of uncollectible expense associated with the provision of delivery services only. (Resp. Ex. 39.0, pp.7-8).

Mr. Stafford understood Ms. Ebrey's recommendation to be applying the same uncollectibles rate to the SPA as applied to base rate revenues, with the further understanding that base rate revenues be equivalent to delivery service revenues as established in this proceeding and subsequent delivery service rate cases. The derivation of the electric delivery service portion of Uncollectibles is a percent based upon test year Uncollectibles divided by electric distribution, transmission, and power supply revenue. (Ameren Ex. 6.05, p.3). The same uncollectibles rate would be used for the Uncollectibles Factor Growth-Up recovered through Rider MV, as well, and reset in later rate cases (Resp. Ex. 36.0, p.42).

In summary, while the Ameren Companies do not believe this is a disputed issue, to the extent that is not the case, we recommend the Commission adopt this approach.

2. Development of Meter Costs v. Customer Costs

One of the key rate design proposals being made, are uniform Meter and Customer charges. (AmerenIP Ex.10.0, pp.8-11). Initially Staff expressed concern over the difference in meter costs and meter revenue being recovered by unbundled Meter charges. (ICC Staff Ex. 8.0, pp.3-5). In rebuttal, Staff witness Mike Luth accepted the Ameren Companies' explanation, and agreed the cost structure was not an impediment to a meter service provider wanting to provide such service. Mr. Luth, though, raised the question about the percentage of costs in meter-related accounts recovered through the meter charge in the various rate classes, noting the percentage of meter revenues versus meter costs is relatively low for DS-3 and DS-4 as compared to the percentage for DS-1 and DS-2. (ICC Staff Ex.19, p.3).

Mr. Jones explained and justified why percentage differences are expected. Because most DS-1 and DS-2 customers are metered at a secondary voltage, and the more costly current transformers ("CTs") and potential transformers ("PTs") are not needed and where such transformers are needed for the DS-3 and DS-4 customers, it logically follows that the percentage of meter revenue to meter costs would be relatively low for the DS-3 and DS-4 customers. Stated differently, very few DS-1 and DS-2 customers require CTs and PTs; therefore, there would be a low percentage of costs involved. (Resp. Ex. 41.0, p.17). DS-3 and

DS-4 customers are being served at higher voltages and the cost of CTs and PTs becomes higher for each higher level of line voltage reduction required. Mr. Difani concluded that the transformer costs can range from 30 or 40 times the cost of the meter which results in the differences between meter costs and customer charges as questioned by Staff witness Luth. (Resp. Ex. 40.0, p.6-7).

3. NCP vs. A&P

Staff had no objection to the use of the class costs of service studies for allocation purposes, which relies upon the non-coincident peak (NCP) method. In contrast, CUB witness Thomas proposed the use of the Average & Peak ("A&P") allocation method. The use of the A&P method is opposed by both the Ameren Companies as well as the IIEC.

CUB witness Thomas advocated a number of reasons for moving away from the traditional NCP method that is the basis for the Ameren Companies' cost of service method. He suggested this was the first Ameren Company distribution only rate case to determine residential delivery service rates. In this regard, Mr. Thomas is absolutely wrong. The Commission has set rates for delivery service customers since 1999 for all three Ameren Companies. In each of those proceedings the Commission accepted the NCP allocation method. Later, in ICC Docket Nos. 01-0432, 00-0802, and 01-0637, the Commission approved delivery service rates for residential customers, as well as the other customer classes, and again the Commission approved the use of the NCP allocation method. (Resp. Ex. 40.0, p.2).

At the heart of the CUB proposal is its failed understanding as to how the distribution system is designed. CUB witness Thomas contends that the demands imposed by ratepayers throughout the year justify the use of the A&P allocation of distribution demand facilities. In reality, the distribution system must be capable of delivering electricity to each customer and be sized adequately for the maximum demand of that customer or group of customers.

Accordingly, the allocation of the distribution system costs should be based upon a combination of individual or customer group non-coincident peak demands. (Resp. Ex. 19.0, p.5).

Further, the A&P method allocates cost not based on the "average" use of the distribution system, but also the usage by customer classes at the time of peak, resulting in a double counting of class demands. This is so because the average demand is also counted as part of the peak demand. (Resp. Ex. 40.0, pp.3-4).

The A&P approach relies heavily on energy usage, a variable allocator, to allocate fixed distribution costs. Such an approach is counter intuitive to the fact that maximum demand is a significant factor in the design and construction of utilities' distribution system. Indeed, the proof of the A&P allocators' over-emphasis on energy usage as a driver in the allocation process was demonstrated by examples provided by Mr. Difani. In those examples, even though each class required the same amount of investment, the A&P allocation would allocate substantially less to one class as compared to the other. (Resp. Ex. 19.0, pp.6-7).

Mr. Thomas also defends the A&P allocation method by referring to a prior Commission gas case. Mr. Difani explained that while there are similarities between the natural gas and electric distribution systems in concept, there are also material differences. For example, demands on electric systems vary significantly hour by hour, and the coincident peak is described as that use in one hour. For gas systems, the coincident peak is described in terms of a daily peak. Also, electric systems are considered to be "on-demand", that is, there is no storage system for electric power and energy and power supply is drawn and taken by customers as it is being generated. In contrast, gas can be stored underground or by another form of storage which is called "line packing". (Resp. Ex. 40.0, pp.4-5).

Particularly troubling is the failed attempt of the CUB analysis in demonstrating the cost impact associated with the A&P allocation proposal. There is no doubt the net effect of the A&P allocation is to re-distribute more costs to the non-residential customers. But what the Commission cannot know from the CUB analysis is how much is being re-distributed. CUB Exhibit 4.02 was an update to CUB Exhibit 2.03. Mr. Thomas testified that CUB Exhibit 2.03 explains the results of modifying the Ameren Companies' cost of service study by using his proposed A&P method. He states unequivocally, "… the use of the A&P allocators tends to distribute more costs to commercial and industrial customers and fewer costs to residential customers". (CUB Ex. 2.0, p.14). Whichever allocation method is used, the revenues to be recovered by the Ameren Companies should be the same – to this there is no dispute. Yet, an examination of, for example, Schedule 4.01 (AmerenCILCO Proposed) with regard to AmerenCILCO shows that under the NCP method AmerenCILCO will recover $138,184,000 yet under the A&P method AmerenCILCO will recover $125,853,000. (Tr. at 965-970). These discrepancies run through the other Schedules 4.01 for AmerenCIPS and AmerenIP as well. (Tr. at 965-970).

When challenged about these discrepancies, Mr. Thomas then claimed the schedules were only for illustration purposes and not intended to form a correct allocation of costs. (Tr. at 973). Mr. Thomas never did take issue with the claim that the exhibits were in error and when asked whether because of the magnitude of the error, one could discern the impact of this proposal, he could only respond that he would have to further review his analysis. (Tr. at 973).

In conclusion, there has been no valid demonstration that the Commission should abandon the use of the NCP method for purposes of allocating costs amongst the customer classes. Further, there is every reason based on the record in this proceeding to thoroughly reject the A&P allocation method. Not only is the A&P method inappropriate for allocating fixed distribution system costs because of its undue reliance on energy usage, but the fact remains this Commission cannot know the full impact of using the A&P allocation method, in terms of the amount of costs that would otherwise be recovered from non-residential customers.

D. Inter-Class Allocation Issues

1. Allocation methodology

The Ameren Companies presented a traditional embedded class cost of service study that is used to determine for each rate class cost based responsibility of the level of revenues necessary to meet the Ameren Companies' operating and maintenance expenses, depreciation provisions applicable to their investment in utility plant, property taxes, income and other taxes, and the fair rate of return on utility rate base. The Ameren Companies' class distribution allocation methods are consistent with the Commission's recent rulings in Docket Nos. 01-0637, 00-0802, and 01-0432, for AmerenCILCO, AmerenCIPS and AmerenIP, respectively. (See AmerenCILCO Ex. 9.0, p.5).

The Ameren Companies used a two step criteria class revenue requirement methodology, to modify the proposed delivery service rates set at the equalized rate of return, for each Ameren Company. First, the DS-1 through DS-3 rate classes were targeted to receive an equal percent revenue change from existing to rebundled service. This had the effect of reducing the DS-1 revenue requirement and increasing the DS-2 and DS-3 revenue requirement. The second step was to ensure that the DS-4 class would receive at least a 5% increase. Originally, this second step would only have applied to AmerenCILCO. (AmerenCILCO Ex. 10.0, pp.5-6). However, a correction to the cost of service study effectively eliminated the second step and it is no longer at issue.

a. Staff Position

Staff witness Harden explained the Ameren Companies have to re-distribute a portion of the class equalized revenue requirement in order to lessen the impact on the customer's total bill. As a result, the proposed increase for the DS-1 through DS-3 classes is an average increase of 15.56% for AmerenIP customers. For the AmerenCIPS' customers in the DS-1 through DS-3 rate classes, they receive an average of 2.78% increase. (ICC Staff Ex. 18.0, p.3). Where Staff differs with the Ameren Companies, is with respect to the revenue allocation methodology affecting AmerenCILCO. Ms. Harden recommended that the DS-2 rate increase should increase from 2.97% to 5.94%, and that the remaining revenue requirement should be recovered from the DS-3 customers. By this adjustment, Staff intends to minimize or limit the rate impact for the DS-2 class. (ICC Staff Ex. 7.0, p.8).

Ameren witness Jones disagreed because limiting the DS-2 rate class to only a 4.51% increase would create an undue revenue deficiency of more than $6.6 million, assuming full recovery of the requested revenue requirement. The increase to the DS-3 class would more than double, increasing from 13.02% to more than 26%. (Resp. Ex. 41.0, p.3). Rather than accept the Staff position, the Commission should affirm the Ameren Companies' treatment of the AmerenCILCO DS-2 and DS-3 classes. In the end, the DS-3 revenue requirements should be close to the level that will produce an equalized rate of return for the class. (Resp. Ex. 20.0, p.8).

b. Kroger Position

Kroger witness Kevin Higgins testified that all distribution delivery rates should be based on cost of service, with an equalized rate of return for each class. He opined that the DS-3 and DS- 4 rates be set at cost. (Kroger Ex. 1.0, p.4) As explained elsewhere, in its direct case AmerenCILCO's DS-4 class would have been subject to a 5% minimum rate increase floor, however, there was a correction in the class cost of service in the rebuttal case such that the DS-4 class will now receive an increase greater than 5%. Accordingly, the 5% minimum threshold is no longer applicable to AmerenCILCO.

The revised cost of service study also showed a rate decrease for the AmerenCIPS DS-4 customers, which then could have been subject to the 5% minimum rate increase criteria. However, because the increase to the other AmerenCIPS' rate classes is no more than 14% as compared to the projected increases for the other AmerenCILCO delivery service rate classes, the Ameren Companies concluded there was no further need to hold the DS-4 class to a minimum increase threshold. Therefore, the DS-4 rates will be set at cost of service. (Resp. Ex. 20.0, pp. 5-6). This, then, alleviates Mr. Higgins, Mr. Selecky, and IIEC witness Robert Stephens' concerns as to this issue.

Mr. Higgins also proposed a common Distribution Delivery Charge for DS-3 and DS-4 based on their joint cost of service. He recommends a common demand charge that applies to both DS-3 and DS-4 customers. (Kroger Ex. 1.0, p.3).

Mr. Jones testified that while the Kroger proposal is consistent with the long term goal of establishing cost based rates, to do so at this time would result in the DS-4 charges increasing to an unacceptable level. For example, accepting the Kroger position would require an AmerenIP DS-4 increase to about 415%. Instead, the better choice would be to set DS-4 rates equal to cost of service. (Resp. Ex. 20.0, pp.6-7).

Mr. Higgins claimed further by that DS-3 customers may have an incentive to increase their demand to 1,000 kW to qualify for the lower DS-4 rates. Unfortunately, Mr. Higgins' simple statement fails to acknowledge or consider the rates in their totality.

Customers will be assigned either the DS-3 or DS-4 rate based on the billing period from February 2005 through January 2006. Customers will not be permitted to cross over to DS-4 until June 1, 2008, and this will be based on usage from July 2006 through June 2007. Therefore, the customer that is considering taking service under DS-4 because of the lower rates as Mr. Higgins' supposes, must take into account its billing demands in 2008 and reach a demand level of at least 1,000 kW sometime between the period of July 2006 and June 2007. Whether these customers can increase their demand during that period of time is an unknown and moreover, whether they would benefit is also an unknown. This is so because a customer that would artificially increase its demand in order to take the DS-4 rate will pay the higher Distribution Delivery Charge for the month and higher Transformation Charges for the ensuing year. Further, once a customer is taking service under DS-4, its ability to switch supply options change. Whether or not a DS-3 customer will actually view the lower rates under DS-4 as an incentive, given the uncertainties described above and the potential for higher charges is really nothing more than speculation. (Resp. Ex. 41.0, pp.4-5).

Mr. Higgins' analysis was also shown to be flawed. While his proposal helps DS-3 customers supplied from primary voltage lines, it hurts those DS-3 customers that are supplied from high voltage lines. DS-3 customers taking service from high voltage lines will actually be subject to a greater departure between the DS-3 and DS-4 rates. (Resp. Ex. 41.0, p.6).

c. Wal-Mart Position

Wal-Mart witness Selecky generally discussed the desire to ensure that rates be set at cost. In his direct testimony, he recommended that any reduction from the requested revenue requirement be allocated to those service classifications that are above cost of service. (Wal-Mart Ex. 1.0, pp.23-24). The Ameren Companies rejected Mr. Selecky's position, because different approaches to class revenue responsibility are needed. (Resp. Ex. 20.0, p.19).

d. CUB Position

CUB contends that the residential and governmental classes are less risky to serve than other customer classes and, therefore, should receive a rate increase no more than 90% of the system average. (Corrected CUB Ex. 2.0, pp.15-18). The working premise for the CUB position is completely without merit.

Ameren Companies witness Jones gave several reasons for rejecting the CUB position, to wit:

- The CUB position is an affront to the Commission's past practice of moving rates toward an equal rate of return or equal proportion of cost responsibility when possible.
- Uncollectible exposure and weather related revenue risks are actually higher for the residential class compared to other rate classes, thus making the residential class more risky than the other classes from a revenue standpoint.
- It should be recognized that the Ameren Company recommended cost of service study actually assigns less cost to the residential and small use customer classes; other parties have questioned whether setting rates at something less than cost is justified.
- The Ameren Company revenue allocation method strikes an appropriate balance between implementing cost based delivery service rates and customer bill impacts, which takes into consideration the Commission- approved bill impact adjustment from the auction cases. The Ameren Company proposal is to reduce delivery service rates to the DS-1 class by 8.7% for AmerenIP, 3.6% for AmerenCIPS, and 16.6% for AmerenCILCO.

(Resp. Ex. 20.0, pp.8-9).

In rebuttal, CUB persisted in its arguments that the residential class was less risky to serve but to no avail. Charts relied upon by CUB witness Thomas intending to show the variability in sales as between the residential class and the non-residential class erroneously portrayed the change in sales from one month to the next. When a two month moving average is used, it is clear that the variability in sales is greatly reduced for the commercial and industrial classes as compared to the residential class. In fact, the commercial and industrial sales are more stable than residential sales, the former providing the utilities with a much more stable source of income throughout the year. (Resp. Ex. 41.0, p.8).

The reason for the variability in sales for the commercial and industrial class as represented by Mr. Thomas is distorted. During the period of July 1998 through January 2000, both AmerenCIPS and ComEd were in the process of implementing new billing systems. This undertaking likely resulted in a month to month variation in the data relied upon by CUB.[7] The problems associated with implementing a new billing system include bills not being issued in a timely fashion or adjusting to the number of days in a billing period. (Resp. Ex. 41.0, p.7-8). Hence, by relying on the faulty data set as did Mr. Thomas, he fails to recognize easily explained commercial and industrial sales variability. Indeed, the corrected data, with appropriate adjustments, show that these classes provide higher predictability and stability of sales to Illinois utilities than does the residential class. As such, CUB's position is unsupported by the record and should be rejected.

e. AG Position

AG witness Rubin had objected to the removal of the 5% rate increase floor applied to the DS-4 class. (AG Ex.2.0, pp.9-10). As discussed elsewhere, it is appropriate to remove this threshold as it would have applied to only AmerenCIPS DS-4 customers in any event, and the increases to AmerenCIPS' customers are relatively modest. (Resp. Ex. 41.0, p.10).

The AG had generally complained about the residential rate impact. Mr. Jones noted the DS-1 rate class was the beneficiary of the DS-1 through DS-3 revenue allocation methodology. Further, the AG has offered no other proposal. (Resp. Ex.41.0, p.11).

[7] The CUB charts intending to show the disparity in sales rely upon different scales for the residential, commercial, and industrial classes, pictorially distorting the results of the CUB analysis. (Resp. Ex. 41.0, p.10).

2. Minimum Distribution System Study

IIEC witness Alan Chalfant and Wal-Mart witness Selecky recommended that distribution plant accounts 364-Poles, 365-Overhead Conductors, 366-Underground Conduit, 367-Underground Conductors, and 368-Line Transformers should be allocated based on a minimum distribution system basis. (IIEC Ex. 2.0, pp.18-22; Wal-Mart Ex. 1.0, pp.15-23). The Ameren Companies believe there is merit to the allocation of these plant accounts in the manner being recommended, however, the Commission has indicated a preference for the NCP method. Conversely, the Commission has shown no interest in the minimum distribution method. (Resp. Ex. 19.0, pp.3-4).

Only if the Commission is convinced that IIEC and Wal-Mart have put forth some persuasive reasoning different than what the Commission has heard in the past, the Ameren Companies should not be ordered to undertake time consuming and costly studies for the benefit of certain parties. Such a study could take one person up to nine months to complete. (Resp. Ex. 19.0, p.4; Tr. at 322).

E. Rider QF

The Ameren Companies proposed Rider QF-Qualifying Facilities, which would pay QF customers a rate based on MISO locational marginal prices (MISO LMP). (See AmerenCILCO Ex. 10.0, p.38). Basing the price to be paid to these customers on locational marginal pricing is appropriate because the amount of energy purchased in the auction to serve Rider RTP-L customers, is equal to the customers' real time requirements less the energy provided by the QF. This amount represents the Ameren Companies' avoided costs under the BGS-LRTP supplier forward contract (because it is the cost not being paid to the supplier), and that cost in a given hour is equal to the MISO locational marginal price for the same hour. (Resp. Ex. 20.0, p.30).

Notably, Part 430 of the Commission's rules requires the payment to the customers be based on the utility's avoided costs. Specifically, 83 Il.Admin.Code Part 430.30 provides as follows:

> "Avoided costs" means the incremental costs to the electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, the utility would generate itself or purchase from another source (18 CFR 292)."

Staff witness Rockrohr did not object to the use of locational marginal pricing but recommended the Ameren Companies include a fixed price payment option within Rider QF. Mr. Rockrohr's reasoning was essentially two-fold: a small prospective QF owner may have difficulty predicting an order of magnitude for the value of excess generation and second, some QF owners would find it impossible to conduct a cost analysis unless a fixed cent per kWh option was available. (ICC Staff Ex. 9.0,p.17).

It should be observed Mr. Rockrohr has no basis in fact for his belief or perception as to what QF owners believe or do not believe. He conducted no survey of any kind. He did not meet with one QF customer about this matter. He did not know how many QF customers were located in the Ameren Companies' service territories. He did not know how much load was being served by QF facilities in the Ameren Companies service territories. (Tr. at 795-798). In the end, his contentions about what is best for QF customers, is simply a matter of conjecture and speculation.

Aside from the above infirmities, the notion that a prospective QF customer would perform some extended cost benefit analysis based on an Ameren Company stated tariff rate makes no sense. As pointed out by Mr. Jones, and as required by the Commission's rules, the current QF rates change every year. If, indeed, a prospective QF customer intended to do some meaningful cost benefit analysis, that customer would examine a variety of data sources and review historical and forward price information provided by the Ameren Companies, as well as

MISO data. (Resp. Ex. 20.0, p.31). A fixed price option lends nothing to a proper evaluation of the QF economics, and this was not refuted by Staff.

More importantly, the effect of the Staff proposal will result in a mismatch between cost and revenues arising from paying QF customers fixed cents per kWh value. This is so because the BGS-LRTP purchases, which are used to supply Rider RTP-L customers, are off-set by any QF production. These suppliers will be paid at the MISO LMP prices for energy they provide, and the Ameren Companies will charge Rider RTP-L customers the same MISO LMP prices for energy consumed. This will create a balance in the costs incurred and revenues paid. However, a customer taking the fixed price option under Rider QF will create an imbalance between the cost and revenues in every single hour in which the MISO LMP does not equal the fixed price option. (Resp. Ex.20.0, pp.31-32). Mr. Rockrohr did not disagree that Rider RTP-L customers could pay more for their energy because of QF customers taking the fixed price compensation package (Tr. at 794).

Mr. Jones put forth examples of the disparate impact as a result of customers taking the fixed price option. They demonstrate the mismatch between the Ameren Companies' avoided costs and a fixed QF payment, and in the end the mismatch flows through the Rider RTP-L customers. Rider RTP-L customers will pay either a higher or lower rate than otherwise required. (Resp. Ex. 20.0, pp.33-34).

Aside from Rider RTP-L customers paying something different than the cost to provide them energy, which is an affront to cost causation principles utilized in ratemaking, the price disparity is likely to have a chilling effect on customers interested in Rider RTP-L. RTP appears to be the bedrock service that will help ratepayers control their energy costs post 2006. Indeed, the Commission has gone on record and opened rulemakings to support RTP. It would be counter productive to come out of the gate with a price for RTP that is wrong. Customers taking real time pricing service have an expectation that they will pay an hourly price for energy based on market conditions and will seek to take advantage of the market. However, under the Staff proposal, the hourly price will not reflect the market. Instead, the RTP-L price under the Staff proposal reflects the fixed price option subsidy.

Staff counters by suggesting over some period of time the fixed price option and the MISO LMP price will be about the same and therefore Rider RTP-L customers would be indifferent. (ICC Staff Ex. 20.0, p.6). Mr. Rockrohr never explains why that would occur and it seems self evident that if it did, it would only be a matter of coincidence. Further, the fixed price option will change from year to year, adding to the real unlikelihood the prices will someday balance out.

The Ameren Companies are aware the Commission has accepted the Staff's proposal in the ComEd delivery service tariff case, that is, to require a fixed price option with respect to ComEd's proposed Rider POG. Nonetheless, the Ameren Companies maintain the record in this proceeding overwhelmingly demonstrates the impropriety of using a fixed price option. The Ameren Companies recommend at the very least that the Commission support the use of the MISO LMP price only for Rider QF and in time, based on experience in the ComEd service territory, examine again whether small prospective QF customers have any desire for a fixed price option.

F. Supply Procurement Adjustment

1. Recovery of supply-related costs

At issue as between CNE/PES in the Ameren Companies is the recovery of supply related costs to the SPA. Both Dr. O'Connor and Mr. Domalgaski basically take the same position, that the Ameren Companies should recover all supply related costs through the SPA. The Ameren Companies do not disagree with this premise.

As explained by Mr. Cooper in both his rebuttal and surrebuttal testimonies, categories of supply related costs include the direct and indirect costs of procuring and administering power and energy supply for all customers, except for those costs recovered from customers and other stated charges. Mr. Cooper testified the costs to be recovered include professional fees, cost of engineering, supervision, insurance, payment for injury and damage awards, taxes, license, and other administrative and general expenses not already included in the auction price for power supply. Other costs to be included are capital and operating costs for generation resources incurred outside the auction process and any costs assigned to the power supply administration function, as approved by the Commission, from time to time. (Resp. Ex. 39.0, pp.6-7). As can be plainly seen, the costs that are intended to be recovered through the SPA are, in fact, supplied related.

2. Amount of supply-related costs

There is no dispute between Staff and the Ameren Companies that the amount of $812,857 for Ameren Company personnel and related costs necessary to obtain the power supply should be recovered through the SPA. Resp.' Exhibit 36.14, Schedule 1, provides the amounts that have been specifically quantified and attributable for recovery by Staff or intervenors. The SPA adjustment was detailed in Mr. Stafford's supplemental direct testimony. (Ameren Ex. 6.05, p.2).

Staff witness Ebrey in her rebuttal testimony, disagreed with the amount of BGS tariff support costs as they were quantified by the Ameren Companies on Respondent's Exhibit 16.15, claiming they should be recovered through the SPA and not through the delivery service rates as proposed by the Ameren Companies. The overall level of costs to be recovered, however, is provided for in Resp.' Exhibit 36.5 and included on Resp.' Exhibit 36.14, Schedule 1.

Should the Commission ultimately find that the amount of BGS tariff costs supported differs from the amounts proposed by the Ameren Companies, then the amounts shown on Resp.' Exhibit 36.14, Schedule 1 would need to change. Mr. Stafford was of the view that this would satisfy Staff witness Ebrey with regard to the concerns she outlines in her testimony. (ICC Staff Ex. 13, p.26.).

3. SPA tracking through the Market Value Adjustment Factor

The Ameren Companies have proposed the recovery of SPA costs via an adjustment mechanism within Rider MV and its associated MVAF mechanism. This is recommended because the Rider MV adjustment mechanisms have the unique ability to precisely recover the SPA costs established by the Commission. In effect, the use of a tracking mechanism similar to the Market Value Adjustment Factor ("MVAF") within Rider MV accounts for a change in the kilowatt hours sold and then adjusts the charge to be recovered with respect to the SPA costs. (AmerenCIPS Ex. 8.05, pp.4-6; Resp. Ex. 18.0, p.3).

Mr. Cooper testified by way of example of the appropriateness of tracking SPA costs through an MVAF type mechanism within Rider MV. Assume the SPA costs were set at a level of $1 million by the Commission, and the number of kilowatt hours sold in a year was 100 million, the resulting charge would be 0.01 cents per kilowatt hour. However, kilowatt hour sales will change due to a variety of factors--weather, customers taking RES supply, economic conditions and so forth. Even though the SPA costs remains at a level of $1 million, the MVAF like mechanism would result in a change or adjustment to the charge to reflect variations in kilo-watt hours sold. There would also be a true-up or reconciliation mechanism to ensure that the

Ameren Companies did not recover any more or any less, than the amount authorized by the Commission. (Resp. Ex. 18.0, p.2).

In contrast, Staff witness Ebrey proposes to utilize test year sales level for determining the SPA rate. Therefore, if the Ameren Companies are required to use fixed kilowatt-hour sales, there will be a mismatch between the approved SPA costs and billed SPA charges. This is so because the utilities will not experience kilowatt hour sales greater than the test year. Assume the test year is 100 units. Assume there is customer switching greater than what has occurred historically. This is a fair assumption because we are moving from low cost rates to market priced rates. Now, there are only 90 units consumed. The 90 units cannot produce the same level of revenue as 100 units. Hence, the Ameren Companies, all things being equal, suffer a revenue shortfall. (Resp. Ex. 18.0, p.4).

As indicated above, the basic difference between Ms. Ebrey and the Ameren Companies is whether the MVAF mechanism should be employed as a complement to Rider MV for the recovery of SPA costs. Clearly, the MVAF mechanism contains a tracking feature that ensures precise recovery of SPA costs, regardless of the level of SPA costs or the level of future power and energy sales under the Ameren Companies' Rider MV. Said preciseness is obviously in the better interests of and represents fairness to all stakeholders and, therefore, the Ameren Companies proposal should be adopted by the Commission.

G. Line Extension Refunds

Section 410.410 governs the Commission's rules regarding line extension provisions. Generally, Section 410.410 outlines a prescriptive protocol by which the utility can extend a customer's distribution system, the amount of free extensions, deposits, and the like. Section 410.410(a)(2) provides that the line extension provisions as outlined in subsections (b) and (c) are not binding in the event the utility demonstrates that its line extension provisions are more favorable to applicants. In this respect the Ameren Companies put forth a proposal that is far more favorable than what is otherwise provided under subsections (b) and (c). Therefore, the Ameren Companies should be excused from the 10 year refund tracking obligation in return for the five year refund tracking obligation and accompanying options.

Mr. Jon Carls on behalf of the Ameren Companies identified the following benefits to residential customers:

- The option to reduce the upfront charge which assumes there will be one new customer extended from the extension, in return for making the payment become a non-refundable contribution.
- The change from existing practices to make the demarcation point between the line/service extension be the customer's property line, which will result in more extensions meeting the definition of "service" instead of "line", and consequently the amount of the payment will often be lower.
- An option for the customer to install conduit for service extensions and possibly for some line extensions, which could reduce the amount, if any, of the required payment.

(Resp. Ex. 31.0, pp. 10-11).

Staff took issue with the legitimacy of these benefits as it related to residential customers (though acknowledging that for other customers the proposal is more favorable); however, all of Mr. Rockrohr's claims were soundly refuted. Based on the Ameren Companies actual use of the concept identified in the first bullet point, applicants generally know whether someone else will be utilizing that extension in the near future and have often agreed to pay a lesser amount upfront and forego the tracking/refunding possibility. With regard to the second bullet point, the change of demarcation point, historically the cost for service extensions are almost always lower than for line extensions and, therefore, customers will see a benefit to change of the demarcation point. As for the last bullet point, the customer's option to install conduit, Mr. Carls explains the cost to the customer will be at a reduced charge, perhaps even free, depending on the actual footage. (Resp. Ex. 51.0, pp.2-3).

The Ameren Companies maintain that in return for the above options, reducing the tracking of the refund from 10 years to five years is a clear win-win for customers. Implicitly realizing the merits of the proposal, Staff witness Rockrohr suggested that the Ameren Companies offer both, that is, offer the package of options but also be required to continue to track refunds over a 10 year period of time.

The Ameren Companies would have to seriously consider whether providing the options as well as the burden of tracking refunds over both a five and 10 year periods of time, is appropriate, that is, should the Commission side with the Staff on this position, the Ameren Companies will have to reconsider making the options available. (Resp. Ex. 51.0, p.3).

H. Residential RTP Program

CUB, in its direct case, recommended a real time pricing ("RTP") program. (See Corrected CUB Ex. 2.0, pp.21-36). The Ameren Companies initially took issue with the CUB proposed RTP program as there was a lack of detail and other issues that had yet to be resolved. (Resp. Ex. 20.0, pp.20-22). In rebuttal, CUB witness Thomas provided more detail, such that the Ameren Companies do not object to the CUB proposed RTP program subject to certain adjustments as reflected in Mr. Jones' surrebuttal testimony. (See CUB Ex. 4.0, pp.34-40).

The adjustments are discussed at page 27 of Mr. Jones' surrebuttal testimony and would result in an incremental meter lease cost of $6.94, as well as an increase to program costs by an additional $193,074.00, which results in a per residential customer per month value of 11.8 cents. (Resp. Ex. 41.0, p.27). The other adjustment comes from using a four year average instead of three, increasing the true cost of implementation from $1,067,488 (CUB Ex. 4.07) to

$1,291,457 (Resp. Ex. 41.0, p.27). The total cost of implementing the RTP program is $1,484,531.

In support of the CUB proposed RTP program, the Ameren Companies developed a new tariff, Rider ESP-Energy Smart Program, identified as Schedule 41.3 to Mr. Jones' surrebuttal testimony. The tariff governs the rules surrounding the residential RTP program. Notably, customers enter into a participation agreement with the program administrator. Space in the program may be limited based on target levels over a four year period of time. Rider ESP also details the conditions that apply to customers taking service under the rate. (See Resp. Ex. 41.0, pp.29-30, Resp. Ex. 41.0, Schedule 41.3).

Finally, implementation of Rider ESP would require changes to the proposed Miscellaneous Fees and Charges provisions in the delivery service tariff. Specifically, additional wording was recommended that would allow a waiver to the Incremental Metering Charges for Rider RTP for residential customers up to the number of program participants as identified by CUB. (Resp. Ex. 41.0, p.31).

I. Uniform Lighting Rates for AmerenIP

In its direct case the Ameren Companies explained their approach to developing the various types of lighting services as well as the cost of service. Mr. Jones explained in great detail the proposed standard lighting offerings including Area, Directional and Decorative. He further explained that existing lighting service is separated between "street lighting service" and "protective lighting service". (See generally AmerenIP Ex. 10.0, pp.24-25).

In terms of the cost of service, Mr. Jones testified the cost associated with providing street/protective and residential/non-residential services are virtually the same. In fact, "street protective" lighting service has been priced the same for AmerenCIPS and AmerenCILCO. However, for AmerenIP, the level of the increase to the residential Protective Lighting Service would be several times the average increase and, therefore, AmerenIP initially proposed to mitigate the increase to residential Protective Lighting customers. AmerenIP then proposed to increase prices to Street Lighting to produce a relatively modest increase, and use the additional revenue contribution to reduce prices for Protective Lighting. AmerenIP's proposed prices would produce increases of about 15% for the Street Lighting group, and 32% and 43% for the non-residential and residential Protective Lighting groups, respectively. (AmerenIP Ex. 10.0, pp.25-26).

Cities witness Richard Cuthbert recommended that lighting rates be set at cost of service, that is, there would be no interclass subsidies. In the alternative, Mr. Cuthbert recommended that all of AmerenIP's other rate classes would share in the subsidy.

In light of the Cities' rebuttal position and the lack of any objection to the Cities' recommendations, AmerenIP re-evaluated the DS-5 revenue allocation and rate design proposal for AmerenIP. Mr. Jones testified there was some merit to the Cities' position insofar as Protective Lighting is an elective service whereas Street Lighting tends to be an expected public service. While the financial impact to a municipality could be large, the financial impact to residential customers would be relatively modest. Therefore, the Ameren Companies have no objection to uniform pricing for comparable Street Lighting and Protective Lighting services.

The Ameren Companies do oppose Mr. Cuthbert's alternative, where the subsidy would come from other rate classes, because all other customer classes are proposed to receive delivery service increases greater than 15%. The point being, exacerbation of the rate increases should be minimized. If any subsidy is warranted, it should come from the Street Lighting group. (Resp. Ex. 41.0, pp11-12).

Finally, Mr. Jones corrected a number of values relied upon by Mr. Cuthbert. The proposed and corrected values are displayed in the table at page 16. (Resp. Ex. 41.0, p.17). There does not appear to be any dispute as to the correctness of these values.

VI. MISCELLANEOUS SERVICES ISSUES

Each of the Ameren Companies submitted proposed tariffs for metering services and line extensions. (*See* Central Illinois Light Company d/b/a AmerenCILCO, Proposed Ill. C. C. No. 35, Original Sheet No. 4.009-4.015; 4.021-4.022; Central Illinois Public Service Company d/b/a AmerenCIPS, Proposed Ill. C. C. No. 35, Original Sheet No. 4.009-4.015; 4.021-4.022;; Illinois Power Company d/b/a AmerenIP, Proposed Ill. C. C. No. 35, Original Sheet No. 4.009-4.015; 4.021-4.022.) The International Brotherhood of Electrical Workers, AFL-CIO Locals 51, 309, 649, 702 and 1306 ("IBEW" or "Unions") intervened in this proceeding under the guise of a "just and reasonable" rate investigation , to object to these tariffs on the basis that the tariffs, if approved, would result in job losses for IBEW members.[8] For example, IBEW argues the utility should not allowed to use a contractor that has employees with a different skill set than "utility employees that are replacing or personnel working for an ARES or meter service provider." and that such practice is not "just and reasonable". (IBEW Ex. 1.0, 9.19.)

The record evidence, however, fails to establish any meaningful nexus between, on the one hand, the tariffs; and on the other, the practices that the IBEW claims will result in job losses. The Ameren Companies' metering services tariffs, for example, are irrelevant to whether outside service providers hired to expand the Ameren Companies' Automated Meter Reading ("AMR") system in Illinois are subject to Commission certification as "meter service providers" under 83 Administrative Code Part 460, as the IBEW claims they are. Likewise, the Ameren

[8] Although five local unions intervened in this proceeding, the IBEW submitted testimony only from Locals 51 and 702.

Companies' line extension tariffs, which would permit customers to install their own conduit and also authorize pilot programs to explore allowing subdivision developers to install some distribution facilities, has already been the subject of both a labor grievance and a prior Commission proceeding. The Commission found that labor matters have nothing to do with the Public Utilities Act ("Act") and therefore are not the appropriate subject of Commission proceedings. *Investigation Into the Proper Allocation of Line Extension and Service of Installation Costs*, Docket No. 03-0767, Order of Rehearing of April 6, 2006, at 3.

The IBEW is simply trying to re-litigate its labor disputes in the context of a distribution rate case. Indeed, each of its witnesses reserved to themselves the right to "…to discuss the results of the arbitrator's decision in the IBEW's rebuttal testimony." (IBEW Ex. 1.0, p.31) But the IBEW has failed to establish that any aspect of the Ameren Companies' metering services or line extension tariffs is unjust or unreasonable under the Act. The Commission will approve these tariffs.

A. Line and Service Extensions

IBEW complains about two aspects of the Ameren Companies proposed line extension tariffs. First, they complain that residential customers and subdivision developers should not be permitted to install their own electric conduit. Second, they argue that subdivision developers should not be permitted to install their own distribution facilities. The Unions have failed to show that either policy is unjust or unreasonable.

The evidence in this proceeding shows that the most common method for new service installations is to direct-bury the conductor. (Tr. at 660, 699-700.) The Ameren Companies' proposed tariffs would allow customers and subdivision developers, at their option, to have the conductor installed in a plastic conduit. (Tr. at 657.) A conduit provides greater protection against accidental line strikes than bare conductor. (Tr. at 639.) For customers that choose to install conduit, the customer is permitted to dig the trench and also to lay the conduit in the ground. (Tr. at 661.) Ameren Company employees will then install the conductor in the conduit and make the necessary service connections. (Tr. at 661-662.) All customer-installed conduit must be installed in a manner consistent with good engineering practices and is subject to inspection by the Company before any service connections are made. (Resp. Ex. 51, p. 4) The tariffs also seek authority to "develop alternative options for developers regarding installation of electric infrastructure in Subdivisions, which may include but are not limited to: developer installation of some distribution facilities . . . ." (*E.g.*, AmerenIP Ill. C. C. No. 35, Original Sheet No. 4.015(iv).) The Ameren Companies developed the line extension tariffs because of concerns expressed by customers over the cost and timeliness of new installations. (Tr. at 658.)

The IBEW argues that allowing customers to install conduit, or allowing developers to install their own distribution facilities, constitutes "unbundling" under Section 16-102 of the Act because the Ameren Companies are proposing to allow customers and contractors to perform work previously performed exclusively by them. (IBEW Ex. 2.0 , p. 40.) They further argue that where a utility proposes to offer an "unbundled" service, the Commission, in determining whether tariffs providing for such services are just and reasonable, is required to consider the effect of unbundling on utility company employees, as stated in Section 16-108(a). (*Id.*) Because the Ameren Companies' line extension tariffs supposedly will result in a loss of jobs for IBEW members, the IBEW urges the Commission to reject the tariffs as unjust and unreasonable.

IBEW cites no authority for its claim that allowing customers to install conduit constitutes "unbundling." In January 1999, in Docket No. 99-0013, the Commission entered an order initiating a proceeding under Section 16-108(a) of the Act to investigate and make determinations about unbundling of metering and billing services. At no time during the subsequent 21 months of investigations and workshops, in any of three interim orders in that case, or in the 88 page final order is there a single mention of anything to the effect that allowing a customer to install conduit on its own property constitutes "unbundling." (Resp. Ex. 31, p. 5.) IBEW's witnesses admit that their conclusion that allowing customers to perform this work is their lawyer's opinion, not their own. (Tr. at 653.)

Sections 16-102 and 16-108 do not support a conclusion that allowing customers to install their own conduit constitutes "unbundling." Section 16-102 defines "unbundled service" as "a component or constituent part of a tariffed service which the electric utility subsequently offers separately to its customers." But whether the Commission is required to consider the effect of "unbundling" on utility employees depends on exactly what kind of service is being unbundled. Section 16-108, titled "Recovery of costs associated with delivery services," grants authority to the Commission "to review, approve and modify the prices, terms and conditions of those components of *delivery services* not subject to the jurisdiction of the Federal Energy Regulatory Commission, including the authority to determine the extent to which such *delivery services* should be offered on an unbundled basis." 220 ILCS 5/16-108(a) (emphasis added). Thus, if a statutorily-defined "delivery service" is being unbundled, Section 16-108(a) comes into play and the Commission must consider the effect on utility employees of unbundling that service.

The Act makes it clear that not every service provided by an electric utility constitutes a "delivery service." Under the Act, "delivery service" means "those services provided by the electric utility that are *necessary* in order for the transmission and distribution systems to function so that retail customers located in the electric utility's service area can receive electric power and energy from suppliers other than the electric utility, and shall include, without limitation, standard metering and billing services." 220 ILCS 5/16-102 (emphasis added.) By no stretch of the imagination can conduit installation be considered a service component "*necessary* in order of the transmission and distribution systems to function so that retail customers . . . can receive electric power and energy from suppliers other than the electric utility . . . ." The use of conduit in service line extensions is the exception rather than the rule; most of the time the conductor is direct buried. (Tr. at 660.) The testimony at hearing revealed that because of cost considerations, the Ameren Companies expects very few customers to elect to install conduit. (Tr. at 701-702.) Because conduit is not necessary for the distribution of electricity to customers, the installation of conduit is not a "delivery service," and because it is not a "delivery service," the Commission does not need to consider the effects to utility employees of "unbundling" this service.

Allowing subdivision developers to install their own distribution systems also cannot be considered "unbundling" under Section 16-102. Under the proposed tariffs, the Ameren Companies are not proposing to "unbundle" the installation of distribution facilities in the sense that any customer will be permitted to install its own distribution facilities. The tariffs merely propose to give the Ameren Companies the authority to develop pilot programs to determine the feasibility of allowing a limited class of customers; *i.e.*, subdivision developers; to hire their own contractors to install distribution facilities. (*See* Resp. Ex. 51.0, p.8.) Upon installation, these facilities would then be sold to the Ameren Companies. (Tr. at 663.) The Ameren Companies' IBEW employees would continue to service these facilities, just as they do today. (Tr. at 664.)

The IBEW's direct testimony could not be clearer about what their chief complaint with the tariffs really is: "What we're talking about here is a dramatic loss in man hours that would otherwise be performed by IBEW members." (IBEW Ex. 2.0 , p. 37.) Whether this is true is irrelevant. The IBEW's concern about job losses clearly implicates a labor relations issue that is beyond the scope of this or any other Commission proceeding. *Investigation Into the Proper Allocation of Line Extension and Service of Installation Costs*, Docket No. 03-0767, Order of Rehearing of April 6, 2006, at 3. Moreover, as explained above, the line extension policies do not implicate "unbundling" of any "delivery service." Accordingly, there is no basis for the Unions' claim that Section 16-108(a) requires the Commission to consider the effects of the proposed tariffs on the Companies' employees.

IBEW also attempts to make the case – unsuccessfully – that the line extension tariffs are unreasonable because they will permit customers to perform dangerous activities. IBEW witness Miller, for example, testified about a number of alleged hazards associated with customers installing their own conduit. One of these hazards is digging into existing utilities. (Tr. at 637.) But as Mr. Miller acknowledges, this hazard exists regardless of whether it a customer or an Ameren Company employee performing the trenching. (Tr. at 637.) This hazard can be reduced by customers' calling J.U.L.I.E. before performing trenching, as they are required to do by law. (Tr. at 638; 220 ILCS 50/.) Mr. Miller also testified about the hazard of flying debris caused by trenching equipment, but conceded that this hazard also exists regardless of who does this work. (Tr. at 639.) Further, in his direct testimony, Mr. Miller discusses the potentially "fatal" risk of trench cave-in. After admitting at hearing that most conduit trenches are only 18 to 24 inches deep, the witness was forced to concede that this "risk" is vastly overstated. (Tr. at 640-641.) Tellingly, while Mr. Miller testified in his direct testimony of at least 23 known instances (which predate this proceeding) where customers have installed their own conduit (Tr. at 641-642), he admitted on cross examination that he is not aware of any instance where the "hazards" discussed in his direct testimony actually happened. (Tr. at 643.) The IBEW's speculation about what could happen if customers install their own conduit is simply contrary to fact.

The IBEW essentially is asking this Commission to find that any tariff provision that results in a reduced workforce is *prima facie* unjust and unreasonable. Nothing in the Act supports this conclusion.

The IBEW has failed to provide any basis to reject the Ameren Companies' proposed tariffs. None of IBEW witnesses testified that any proposed rate or charge for metering or line extension services is unjust or unreasonable, or that any aspect of the metering or line extension tariffs is in any way relevant to whether any costs that the Ameren Companies seek to recover in rates were prudently incurred. The IBEW's entire case is predicated on a theory that any utility policy that results in workforce reductions is necessarily unjust and unreasonable, regardless of whether the policy benefits the utility, its investor, ratepayers and the public. Their theory is fatally flawed; nothing in the Public Utilities Act authorize the Commission to reject tariffs that could lead to workforce reductions. The IBEW's claims should be rejected and the Commission should approve the Companies metering services and line extension tariffs.

B. Metering Services

The Ameren Companies' proposed metering services tariffs state that the Ameren Companies will "own, furnish, install, calibrate, test, and maintain all Company meters and all associated equipment used for retail billing and settlement purposes in its service area," unless the customer hires a Meter Service Provider ("MSP") to perform these services. (*See*, *e.g.*, AmerenIP proposed Ill. C. C. No. 18, Original Sheet No. 4.021.)

The IBEW does not specifically object to the metering services tariffs *per se*. Rather, IBEW's complaint centers on the Ameren Companies' planned expansion of their AMR system. An AMR system consists of a module within individual electric meters that transmits data via a wireless communications system. (Tr. at 712-713.) The electric meter, which is owned by the Ameren Companies, remains the fundamental measure device for electricity consumption. (Tr. at 714-715.) Cellnet Technologies, Inc. ("Cellnet") owns the module inside the meter that transmits data, as well as the wireless communications system that transmits the meter data to the Ameren Companies. (Tr. at 719-720.) The benefits of an AMR system include the elimination of estimated bills, less intrusion onto customer property, better outage response, better information for customer service representatives in assisting customers, and special meter readings on the day requested. (Tr. at 626.) An AMR system virtually eliminates the need for manual meter reads. (Tr. at 713-714.) No IBEW witness challenged or took issue with these customer benefits. (Tr. at 636.)

The Ameren Companies have used AMR in parts of Missouri and Illinois since the 1998-99 time period. (Tr. at 631-632; Resp. Ex. 30, pp.8-9) In October 2005, the Ameren Companies informed the IBEW of plans to expand the AMR system further into the Illinois service territories. (Tr. at 634.) The expansion will require them to replace existing meters with meters containing an AMR module. (Tr. at 719.) The meter exchange will be performed by Terasen Utility Services ("Terasen') as a subcontractor to Cellnet (Tr. at 723-724, 732.) The AMR modules and communications system will be owned and operated by Cellnet. (Tr. at 725.) The agreement between the Ameren Companies and Cellnet requires Cellnet to comply with Part 410, where applicable. (Tr. at 653-654.) The Staff had, in fact, recommended a reference to Part 410 be included as a part of the agreement with Cellnet. (Resp. Ex. 30., p.7.) Notably, IBEW Local 51 has filed a labor grievance over the Ameren Companies' use of Cellnet and Terasen for the AMR expansion. (Tr. at 634.)

IBEW argues that the activities of Cellnet and Terasen in conjunction with the AMR expansion constitute "metering services" as defined in Part 460 and therefore require these entities to become certified under that rule. (Tr. at 651.) But for the Commission to accept this argument, it would have to write Part 410 off the books. Electric utilities such as the Ameren Companies are exempt from Part 460 when they provide metering services within their own service territory. 83 Ill. Admin. Code Section 460.20. Instead, Part 410 applies. 83 Ill. Admin. Code Section 410.100. Although the Unions claim that Part 460 applies to utilities when they use outside contractors (*e.g.*, IBEW Ex. 2.0, p. 18), nothing in Part 460 says that. (Tr. at 653.) Likewise, nothing in Part 410 says that a utility has to use its own employees to perform metering services under that Part.

Cellnet and Terasen are *not* subject to certification under Part 460 because they will be performing work on behalf of Ameren, and not on their own behalf as Meter Service Providers ("MSPs") (Tr. at 748-749.) The work they will perform will be limited to exchanging single-phase meters and maintaining the wireless communications system. (Tr. at 723-725.) Neither contractor will have any direct relationship with customers. Instead, each Ameren Company will "own, furnish, install, calibrate, test, and maintain all company meters and all associated equipment used for retail billing and settlement purposes in its service area." (*E.g.*, AmerenIP Proposed Ill. C. C. No. 18, Original Sheet No. 4.021.) Ameren will be providing "metering services" under its tariff, not Cellnet or Terasen. (Tr. at 732.)

IBEW witnesses parsed through the specific work activities that Cellnet and Terasen will perform to attempt to show that these activities fall within some of the 16 different activities that Part 460.15 defines as "metering services." (*E.g.*, IBEW Ex. 2.0, pp. 12-13.) But nothing in Part 460 suggests that any entity that performs any one of these 16 functions under contract with a utility is a "meter services provider" subject to certification under Part 460. Utilities have hired outside contractors for many years to perform many different kinds of work. IBEW witness Moore, for example, used to work for L.E. Meyers, a company that "did construction and maintenance for utilities." (Tr. at 649.) When an outside service provider such as L.E. Meyers does work under contract with a utility (such as, for example, substation maintenance), nobody would suggest that the outside service provider is engaged in the provision of electric service and therefore subject to Commission regulation as a "public utility." Doing work for a utility and being a utility are two different things. The same can be said for metering services. Providing a limited number of components of metering service under contract with a utility does not make the entity providing those services a "meter services provider." Performing limited subcontractor work at the direction of the utility and providing a competitive metering service are completely different activities.

The Unions' claim that the tariffs will allow unregulated, unqualified personnel to perform metering services, but they never produced evidence to back that claim. The only work associated with the AMR expansion that even involves actual meters is the meter exchange service to be provided by Terasen. IBEW does not dispute that Terasen's employees will receive an amount of training comparable to what AmerenIP's meter changers receive. (Tr. at 656.) The Terasen employees are also represented by IBEW Local 702. (Tr. at 655.) The Unions offer *no evidence* that Terasen employees are, or will, be unqualified. Indeed, they admit that they have no personal knowledge of the level of training, skills or experience of Cellnet or Terasen employees. (Tr. at 654-655.)

Under the proposed tariffs, the Ameren Companies will continue to own electrical meters, just as they always have. The Ameren Companies will continue to inspect and replace meters as necessary, just as they always have. (Tr. at 736, 738.) And, the Ameren Companies will remain subject to the metering service requirements of Part 410. If the Unions come to believe as some future time that an Ameren Company or its contractors have violated Part 410, they are free to file a complaint with the Commission. But the Unions' speculative claims provide no basis for rejecting the Ameren Companies' metering services tariffs.

C. Vegetation Management/Tree Trimming

Staff witness James Spencer recommends that the Commission adopt a new interpretation of Rule 218 of the National Electrical Safety Code ("NESC"), which the Commission has made a part of Illinois Administrative Code 305.20 through incorporation by reference of Section 21 of the NESC. NESC Rule 218(A)(1) states that "[t]rees that may interfere with ungrounded supply conductors should be trimmed or removed." Mr. Spencer testifies that Staff began interpreting Rule 218 as a no-contact rule in October 2002. (ICC Staff Exhibit 21.0, p. 10, line 215.) Notably, if correct, this date does not coincide with the Commission's adoption of any new rule or amendment. Thus, Staff's attempted new interpretation of NESC Rule 218 constitutes illegal rulemaking.

Further, Staff's proposed new rule should not be adopted, because it is an inappropriate interpretation of NESC Rule 218, as shown in the Ameren Companies' testimony. Implementation of such a rule is unnecessary, unwise, unsupported by industry practice, and is contrary to law, as fully set forth in Section V.C.

1. The Ameren Companies' Vegetation and Tree Trimming Practices are Reasonable, Effective and in Compliance with the Law.

Ameren Companies' witness Allen L. Clapp, President of Clapp Research Associates, P.C., Consulting Engineers and President of Clapp Research, Inc., testified that Staff's interpretation of NESC Rule 218 is incorrect. (Resp. Ex. 26.0.) Mr. Clapp is a Member (Chair

1984-1993) of the National Electrical Safety Code (NESC) Committee and the editor of the NESC Handbook, and represented the National Association of Regulatory Utilities Commissioners on the NESC Committee until he became the Chair in 1984, at which time he became an Individual Member of the Committee. Mr. Clapp is a member of the following NESC Subcommittees:

- National Electrical Safety Code Executive Subcommittee 1976-1993 (Chair 1984-93)
- Interpretations Committee 1976-present (Chair 1981-1990)
- Coordination Subcommittee 1978-present (Secretary 1981-84, Chair 1993-present)
- Clearances Subcommittee 1971-present (Acting Secretary over 20 times)
- Strengths and Loadings Subcommittee 1971-present (Secretary 1978-present)

(*Id.* at 2-3.)

Mr. Clapp has served over 35 years on these committees, and is familiar with the NESC, its rules and the changes that have occurred in the NESC over time. As Editor of the NESC Handbook, Mr. Clapp has reviewed every document known to exist relating to the original codification and subsequent revisions of the NESC. Mr. Clapp has been involved in many seminars, discussions, meetings and the like with stakeholders in the industry, who have helped to form consensus around the NESC. (*Id.*)

Mr. Clapp has served on the NESC Subcommittee responsible for Rule 218: NESC Subcommittee 4 on overhead clearances, and has personally examined every document known to exist in the history of this rule. The rule was originally codified as Rule 281 in the 4th Edition (1927) and remained unchanged in the 5th Edition (1941) and 6th Edition (1961). It moved to Rule 218 in the 1990 Edition. Mr. Clapp has personally participated in each of the three modifications to the rule (1977 Ed., 1984 Ed., and 2007 Ed.) – that is, he discussed, considered and debated with his colleagues as to the propriety to each rule change and the associated intent. (*Id.*)

Mr. Clapp testified that each NESC rule recognizes the purpose of the NESC, as stated in Rule 010:

> The purpose of these rules is the practical safeguarding of persons during the installation, operation, or maintenance of electric supply and communication lines and associated equipment. These rules contain the basic provisions that are considered necessary for the safety of employees and the public under the specified conditions.... (*Id.* at 4.)

Mr. Clapp testified that each edition of the NESC has recognized that it may not be practical to prevent contact between portions of trees and utility lines in all cases, due to the competing desires of consumers to (a) have an aesthetic environment (i.e., to limit the drastic pruning or complete removal of trees necessary to absolutely prevent all contact by trees with utility lines and to (b) have economical utility service, but that it is practical to limit such contact between trees and utility lines to levels that are not likely to cause a safety or reliability problem. (*Id.* at 4-5.)

Mr. Clapp testified that there has never been any intention by the NESC to prevent all contact of trees with utility line conductors. On the contrary, the intent of the code has been to require a practical vegetation management program that will limit the opportunity for damage to utility facilities due to contact by vegetation.

Mr. Clapp also testified that the NESC would be updated on August 1, 2006, to clarify the NESC position on its proper intent. Mr. Clapp disagrees with Mr. Spencer's belief that the NESC language intends that utilities must trim trees back far enough that there is no possibility that any limb will grow out and contact an energized conductor before the next pruning cycle.

That is not practical to accomplish under any reasonable vegetation management program. (*Id.* at p. 6.)

Experience with tree growth in various areas of the country has shown that, while it is practical to prune far enough back using the so-called natural pruning method to limit the opportunity for future growth to grow back into the line before the next cycle, it is not possible to absolutely prevent any contact at all between cycles without (a) employing such drastic pruning or complete removal of trees that the adjacent landowners will be ill-served and the health and life of the vegetation will all too often be adversely affected, and (b) spending so much money on needless pruning of trees that would not have grown back into the line that economy of service is adversely affected without significantly increasing system reliability. Indeed, in many municipalities, utilities are not allowed to prune vegetation back far enough to accomplish that goal. (*Id.* at 6-7.)

At the Ameren Companies' request, Mr. Clapp was engaged to study the vegetation management practices in and around power lines. In so doing, Mr. Clapp explained the intended application of NESC Rule 218 as it related to vegetation management around overhead lines. A copy of that report, dated November 29, 2005 and titled National Electrical Safety Code Requirements and Practical Considerations Relative to Vegetation Management Around Overhead Power Lines, has been entered into evidence as Respondents' Exhibit 26.2. The report includes more detail than the above brief discussions. (*Id.* at 7.)

Mr. Clapp's report on the vegetation management practices of the Ameren Companies is attached as Respondents' Exhibit 26.3. In that report, Mr. Clapp concluded that the Ameren vegetation management program of combining (a) a 4-year normal pruning cycle with (b) identifying and scheduling any faster growing trees or trees with pruning limitations such that they might become cycle busters for interim inspection or pruning is a reasonable, practical and pragmatic method of achieving the goal of providing safe and reliable electric service in an economical manner. (*Id.* at 8.)

Notably, Mr. Spencer did not refute any of Mr. Clapp's testimony regarding the correct interpretation of NESC Rule 216 on rebuttal.

In his surrebuttal testimony, Mr. Clapp concludes that Mr. Spencer is uninformed as to the widely accepted industry understanding of the behavior and consequences of vegetation growth in the proximity of conductors. The four-year cycle presently employed by the Ameren Companies, including the targeted treatment of cycle-busters, is expected to limit the opportunity for new growth to contact an energized conductor. In the event that a few trees sprout unexpected sucker growth between cycles, the growth will be small enough that conductor integrity should not be affected. The Ameren Company vegetation management program is reasonably designed and implemented to assure that limbs will be pruned before they reach a size capable of damaging nearby conductors should contact occur. (Resp. Ex. 47.0, pp. 3-4.)

2. The Ameren Companies' Electric Service is Reliable.

The rebuttal and surrebuttal testimony of Ameren Companies' witness Craig Boland demonstrates that Staff's criticisms of the Ameren Companies' service reliability are skewed, because Staff does not normalize for weather-related outages in assessing reliability. (Resp. Ex. 47.0, pp. 1-2.) Mr. Spencer incorrectly claimed in rebuttal testimony that taking weather-related incidents into account The Commission's rules require that Staff take weather and other uncontrollable events into account when assessing a system's reliability:

> The Commission recognizes that circumstances and events beyond a jurisdictional entity's control can affect reliability statistics and the interruptions experienced by customers. The Commission shall consider such circumstances and events when evaluating a jurisdictional entity's reliability performance.

83 Ill. Admin. Code Section 411.140(a)(1). Section 411.140(b)(1) further states:

> When assessing a jurisdictional entity's annual report, the Commission shall consider . . . .
>
> G) The reliability effects of severe weather events and other events and circumstances that may be beyond the jurisdictional entity's control.

And Section 411.140(b)(3) states:

> When assessing a jurisdictional entity's reliability performance, the Commission shall consider . . . .
>
> M) The reliability effects of severe weather events and other events and circumstances that may be beyond the jurisdictional entity's control.

83 Ill. Admin. Code Section 411.140(b)(1).

Craig Boland testified that by using IEEE Standard 1366 for reliability assessment, the Commission could incorporate an objective means to take into account severe weather and other uncontrollable events. (Resp. Ex. 24.0, pp. 2-6.) Mr. Spencer testified in rebuttal that he does not agree with using IEEE Standard 1366, because he believes that (1) "Code Part 411 does not provide for excluding "Major Event Days" as defined in IEEE standard 1366 from the utility reliability reporting, nor does it provide for excluding major storms"; (2) taking weather-related events into account might "favor utilities with poorly maintained systems"; and (3) "customers do not know and are not especially concerned about the particular reasons for their service interruptions." (Staff Ex. 21.0, pp. 2-3.)

The Ameren Companies support the Commission's use of IEEE standard 1366 in assessing overall reliability, for the following reasons. *First,* the Companies state that adoption of IEEE standard 1366 is in accordance with the standards set forth in Part 411, and does not suggest a change in the reporting requirements of Part 411. (Resp. Ex. 45.0, pp. 4.) Ironically, by failing to employ any method to screen out major storms, Staff's analysis cannot distinguish poor performing utilities from those that happen to experience bad weather in any given year. This is clearly inaccurate, is directly contrary to the Commission's Rules, and fails from a practicality standpoint.

Second, as Ameren Companies' witness Craig Boland testified, the IEEE standard 1366 method does not favor poorly maintained systems, because it is designed to identify trends in reliability performance. (Resp. Ex. 45.0, pp. 4-5.) If a utility with a poorly maintained system experiences more and longer outages for the same-strength major storm, then it should also experience more and longer outages for the dozens of lesser storms that occur throughout the year but which do not qualify as Major Event Days. While an additional Major Event Day might be excluded, all of the remaining days with similarly poor performance and an upward trend in reliability results would still be readily identifiable.

Third, Mr. Spencer is wrong in his speculation that many customers do not know and are not especially concerned about the particular reasons for their service interruptions. (*Id.*) Mr. Boland testified that the Ameren Companies have conducted extensive research on this topic. This research, conducted by JD Power and Associates, shows that customers in the Ameren Companies' service territories are very concerned with the reason for their outage. In fact, information on the cause and extent of the outage has been identified by JD Power and Associates as two of the top drivers of customer satisfaction when customers call about their outage. As a result, the Ameren Companies strive to provide this information when customers call regarding an outage.

The Commission agrees that Staff's position is directly at odds with Part 411 of the Commission's Rules, which require for uncontrollable events to be taken into account when assessing a utility's system reliability. The Commission notes that Staff must measure or assess severe weather events and other events and circumstances beyond the utility's control in some manner, in order to comply with Part 411. The Commission agrees with the Ameren Companies that IEEE Standard 1366 an acceptable weather-normalization standard to use in accordance with Part 411.

D. Other

1. Ameren Companies and CNE/PES MOU

In its direct and rebuttal testimonies Constellation New Energy, Inc and Peoples Energy Services Corporation (CNE/PES) raised several issues or concerns with various business practices by the Ameren Companies. In turn, the Ameren Companies explained or justified certain of these concerns and made other commitments. After a continuing dialogue, the Ameren Companies and CNE/PES entered into a Memorandum of Understanding ("MOU") which was made part of the record as Ameren Companies/CNE/PES Joint Exhibit 1. In the MOU a number of agreements were reached that related to a number of business practices, to wit:

a. Ameren will implement an electronic bulletin board or provide on its website a link where answers to commonly asked questions from retail electric suppliers ("RESs") will be posted.

b. Ameren has assigned RESs specific account representatives in the Transmission Services Business Center ("TSBC") that will handle billing related matters that go beyond merely answering transmission billing questions as well as to facilitate the process of answering other RES related questions.

c. Ameren will implement the Electronic Data Interchange ("EDI") 814-C transaction regarding meter numbers and will work with RESs to ensure that the improved processes are working as designed prior to the implementation date.

d. Ameren will provide 24 months of historical usage information, when available, free of charge to authorized RESs and customers starting January 1, 2007.

e. Ameren will apply the Ameren Data Universal Numbering System ("DUNS") number and the DUNS numbers of the individual utilities in a uniform manner across the entire EDI transaction set for each Ameren operating company by no later than September 15, 2006.

f. Ameren agrees to work in good faith with RESs regarding all relevant customer communication plans that may bear upon RES business practices and procedures.

g. Ameren will support the utilization of a "factor" approach to segregate the uncollectibles expenses associated with customers taking bundled service from Ameren and the uncollectibles expenses associated with customers taking only delivery services from Ameren.

h. Ameren agrees to eliminate the Direct Access Service Request ("DASR") Fee and the Standard Switching Fee that appear in the "Miscellaneous Fees and Charges" section of Ameren's proposed tariff.

i. Ameren will support the allocation of the Supply Procurement Adjustment ("SPA") costs to each of the Ameren utilities based on the relative kilowatt-hour sales (i.e. delivered) of each of the Ameren utilities.

j. It remains Ameren's practice to provide all customer account drop information (including retroactive drops) to RESs electronically via an EDI 814-D request.

k. By no later than August 4, 2006, Ameren will post documents/charts to Ameren's website, depicting the customer switching alternatives and enrollment windows for the post-transition period. These documents or charts will be accessible to both RESs and customers under the RES and Customer Portals.

l. Ameren will allow customers to request that Ameren create separate account numbers for their natural gas and electric service upon request. At this time, Ameren does not have a policy objection to allowing Agents, with proper authorization, to make such a request on behalf of a customer. However, the Parties agree to actively and in good faith participate in a workshop process to develop the means and procedures by which Agents can make such requests.

m. As soon as practical, and with a good faith effort to complete this task by no later than September 1, 2006, Ameren agrees to provide the following information on both the Customer and RES Portals on the Ameren Website, to the degree the information is readily available:

- Current Supply Group and Type
- Future Supply Group and Type
- DASR Eligibility Date

- Current rate and supply-type information
- Delivery Services Class
- Ameren Operating Utility

n. Ameren agrees to use a good faith effort, along with CNE/PES, to initiate and participate in a workshop process, to be completed no later than September 1, 2007, similar to the EDI Protocol workshop in which the Parties and other Illinois electric market participants would consider and attempt to resolve issues associated with the expanded use of the EDI enrollment processes and procedures that are currently employed for customers on RES supply to customers that elect service under the Companies' BGS-FP, BGS-LFP and RTP tariffs. This provision may be superseded in the event the Commission would order or otherwise direct Ameren and/or other stakeholders to become engaged in workshops or other like processes, to consider and attempt to resolve the aforementioned issues.

The Ameren Companies have already begun the process of honoring the MOU and will continue to do so. The Ameren Companies respectfully request that the Commission approve the MOU as the means by which to resolve the issues as and between the Ameren Companies and CNE/PES. The Ameren Companies note, however, the MOU expressly reserved the rights of the parties to debate the issues surrounding the recovery of Supply Procurement Adjustment charges as addressed elsewhere in this brief.

Finally, there may be issues not specifically identified in the MOU, or not resolved in testimony and identified as settled issues elsewhere in this brief. Nonetheless, based on the MOU the only issue remaining between these parties in this proceeding relates to the SPA.

2. Distribution Loss Multipliers

The Ameren Companies conducted a study to determine a composite set of distribution loss multipliers. This variable loss multiplier is being offered in lieu of a fixed loss multiplier. The loss multiplier intends to compensate the Ameren Companies for energy lost during the conduction of electricity across the delivery system. (See IIEC Ex. 4.0, p.3). Ameren Company witness Jones explained in great detail the results of the study, and how it affected a change in the Ameren Companies' delivery service tariffs. These changes are reflected in Section 5.B of the Supplier Terms and Conditions. (Resp.Ex.20, pp.36-37; Resp. Ex.41.0, p.24.). The use of the variable loss multiplier benefits customers because it provides for a more accurate price signal, and assigns less total energy losses to customers throughout the year. (Resp. Ex. 20.0, pp.34-38).

The only party to respond to this proposal was IIEC. Mr. Stephens agreed this approach may be a more accurate and fair way to account for system losses than the fixed lost factor method. However, he expressed concern as to the manner by which the loss multiplier may add to the complexity and uncertainty in the process of buying and selling power. (IIEC Ex. 4.0, pp.2-9).

Mr. Jones, through discussion and example, explained that the financial exposure to customers under either the fixed or variable loss multiplier mechanism was quite minimal but that nonetheless customers continued to greatly benefit. (Resp. Ex. 41.0, pp.21-24). It is our understanding IIEC does not oppose the use of the variable loss multiplier and, indeed, the record supports its approval by the Commission.

VII. RESPONSES TO COMMISSIONERS' QUESTIONS

On April 24, 2006, Commissioners Ford and Lieberman posed several questions to the parties regarding demand response programs and real time pricing. The Ameren Companies, Staff and the IIEC responded to the Commissioners' questions.

A. Ameren Companies

The Ameren Companies agree that demand response has the potential to provide benefits to commodity providers, reliability organizations, transmission companies, distribution companies, and electric retail customers, as noted in the International Energy Agency ("IEA") Task XIII: Demand Response Resources Task Status Report dated January 6, 2006. The challenge to all stakeholders that may benefit from demand response is to develop a framework or stakeholder collaboration process that will lead to the development of meaningful, cost effective, long-term, sustainable demand response initiatives. The Ameren Companies have been at the forefront of efforts to devise such a framework or collaborative process in Illinois. The Ameren Companies believe strongly that the complex challenges presented by the demand response issue cannot be fully addressed and implemented with a sole focus on delivery services pricing – that is, through the instant delivery services rate case. Rather, demand response challenges must be addressed with a larger focus on the entirety of the electricity industry in Illinois, through an appropriate Illinois rulemaking procedure.

B. Staff

Staff witness Dr. Eric Schlaf addressed the Commissioners' question on behalf of Staff. Dr. Schlaf noted that pending Docket No. 06-0389 may address the subject of many of the Commissioners' questions, such as the electric utilities' role, if any, in promoting demand response programs; how (or whether) the Commission should promote demand response; how potential benefits of demand response programs may be captured; and, the appropriate methods by which the value of the implementation of demand response programs may be captured. (Id., p. 18)

Dr. Schlaf agreed with the following statement made by Joseph Kelliher, the Chairman of the Federal Energy Regulatory Commission:

. . . One of the acknowledged weaknesses of electricity markets, is lack of effective demand response. That has implications for wholesale markets, leads to great price volatility in wholesale markets, but, ultimately a demand response program revolves around and is centered on the retail consumer. . .

Dr. Schlaf stated that the success of any particular demand response program will depend to a great extent on the actions of retail customers in response to market prices. (Schlaf Reb., ICC Staff Exhibit 22.0, pp. 16-17) As to a distribution company's role in promoting demand response, Dr. Schlaf noted that his understanding of 83 Illinois Administrative Code Part 452 may limit an electric utility's ability to promote demand response programs. (Id., p. 16)

Dr. Schlaf also testified about a report concerning demand response that was completed by the Department of Energy ("DOE") and submitted to the Congress. He stated that the DOE Report identifies several potential systemwide benefits of demand response programs, including "market-wide financial benefits," "reliability benefits" and "market performance benefits." (DOE Report, p. vi). (Id., p. 17) He testified that the subject of how or whether the Commission should promote demand response programs and how the potential benefit of demand response programs could be captured is likely a subject for the demand response rulemaking proceeding. (Id., 18)

Dr. Schlaf stated that he agreed with the DOE Report that historically utility customers have faced fixed rates and thus do not respond to market prices. Since customer demand for rates that are not fixed is extremely low, very few customers are willing to trade the possible benefits of receiving wholesale prices for the cost associated with constantly monitoring market prices in order to determine when the most appropriate time to consume electricity might be on any given day. (Id., p. 19) He added that the lack of price response in retail markets might contribute to concerns about market power in wholesale markets. (Id.)

Dr. Schlaf also stated that he believed that Commission rules restrict the ability of utilities to promote their services; thus, any proposed demand response program would have to be reviewed with those rules in mind. He also believed that utilities cannot be compelled to offer any services that were not being offered when the Customer Choice Law was enacted in December 1997. Further, since there is a difficulty in valuing the benefits of demand response programs. (See, for example, the DOE Report, at p. xvii), Dr. Schlaf recommended that the demand response rulemaking address the valuing of benefits of demand response programs. (Id., p.21)

Finally, Dr. Schlaf testified that there are potential systemwide benefits that could be realized from some demand response programs, which could include a reduction in wholesale price volatility, improved reliability, and improvements in the environment. However, he stated that the benefits are more likely to be realized if there is significant participation among a utility's largest customers because they have the greatest potential to affect market prices through their combined actions in response to market prices. (Id., pp. 21-22)

C. CUB

In response to the Commissioners' questions, CUB proposed a Residential Real Time Pricing ("RTP") Program. In the alternative, CUB suggested that the Commission can view the RTP as a "pilot," and not a program intended to be in compliance with the new RTP law, 220 ILCS 5/16-107.

D. IIEC

IIEC believes the Commission should encourage demand response in a manner consistent with its statutory authority, while recognizing the fact that wires-only companies have only limited opportunities to encourage demand response. IIEC believes the Commission needs to avoid creation of inter-class rate subsidies and hindrance of the development of a competitive market for electricity. Even so, there are opportunities to promote demand response under certain circumstances. For example, a flattened load shape resulting from shifting load to off-peak periods could mean the auction price in Illinois would be lower in recognition of the fact that flattened load shapes are cheaper to serve. As a result, the Commission should encourage demand response where possible and practical.

VIII. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) The Ameren Companies are Illinois corporations engaged in the transmission, distribution, and sale of electricity to the public in Illinois and as public utilities as defined in Section 3-105 of the Public Utilities Act; the Commission has jurisdiction over the parties and the subject matter herein;

(2) the recitals of fact and conclusions of law reached in the prefatory portion of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law;

(3) the test year for the determination of the rates herein found to be just and reasonable should be the 12 months ending December 31, 2004; such test year is appropriate for purposes of this proceeding;

(4) for the test year ending December 31, 2004, and for the purposes of this proceeding, the rate bases are $281, 843, 000 for Ameren CILCO, $428,869,000 for AmerenCIPS and $1,228, 573,000 for AmerenIP;

(5) a just and reasonable return which each Ameren Company should be allowed to earn on its net original cost rate base is 8.848% for AmerenCILCO, 8.507% for AmerenCIPS and 8.946% for AmerenIP, consistent with the conclusions in the body of this Order regarding the capital structure and cost of each component;

(6) for AmerenCILCO, the rates of return set forth in Finding (6) results in base rate operating revenues of $143,061,000 and net annual operating income of $24,938,000 based on the test year approved herein; for AmerenCIPS, the rates of return set forth in Finding (6) results in base rate operating revenues of $237,674,000 and net annual operating income of $36,484,000 based on the test year approved herein; and for AmerenIP, the rates of return set forth in Finding (6) results in base rate operating revenues of $402,216,000 and net annual operating income of $109,908,000 based on the test year approved herein;

(7) the Ameren Companies' rates which are presently in effect are insufficient to generate the operating income necessary to permit the Ameren Companies the opportunity to earn a fair and reasonable return on net

original cost rate base; these rates should be permanently canceled and annulled;

(8) the specific rates proposed by the Ameren Companies in their initial filing do not include the various determinations made in this Order and should be canceled and annulled consistent with the findings herein;

(9) the Ameren Companies should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of $143,061,000 for AmerenCILCO, $237,674,000 for AmerenCIPS and $402,216,000 for AmerenIP, which represent increases of $45,728,000 or 46.98% for AmerenCILCO, $26,691,000 or 12.65% for AmerenCIPS and $146,660,000 or 57.39% for AmerenIP; such revenues will provide each of the Ameren Companies with an opportunity to earn its approved rate of return set forth in Finding (6) above; based on the record in this proceeding, this return is just and reasonable;

(10) the determinations regarding cost of service, rate design, and terms and conditions of service contained in the prefatory portion of this Order are reasonable for purposes of this proceeding; the tariffs filed by the Ameren Companies should incorporate the rates, rate design, and terms and conditions set forth and referred to herein;

(11) new tariff sheets authorized to be filed by this Order should reflect an effective date not less than five (5) days after the date of filing, with the tariff sheets to be reviewed by the Rates Department of the Commission, and corrected, if necessary, within that time period; and

(12) the Ameren Companies shall file copies of FERC Form 60 with the ICC and provide copies to the Manager of Accounting on the day it is filed with the FERC; and

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets presently in effect rendered by the Ameren Companies are hereby permanently canceled and annulled, effective at such time as the new tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general rate increase, filed by the Ameren Companies' on December 27, 2005, are permanently canceled and annulled.

IT IS FURTHER ORDERED that the Ameren Companies are authorized to file new tariff sheets with supporting workpapers in accordance with Findings (10), (11), and (12) of this Order, applicable to service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that any motions, petitions, objections, and other matters in this proceeding which remain outstanding are hereby denied.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission on this ____th day of November, 2006.

(SIGNED) ________________________________