STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Central Illinois Light Company d/b/a AmerenCILCO Proposed general increase in electric delivery and gas delivery service rates. Central Illinois Public Service Company d/b/a AmerenCIPS Proposed general increase in electric delivery and gas delivery service rates. Illinois Power Company d/b/a AmerenIP Proposed general increase in electric delivery and gas delivery service rates.	))))))))))))))))	Docket Nos. 09-0306 – 09-0311 (Consolidated)

PUBLIC
INITIAL BRIEF OF THE STAFF OF THE
ILLINOIS COMMERCE COMMISSION

January 14, 2010

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NOW COME the Staff witnesses of the Illinois Commerce Commission ("Staff"), by and through their undersigned counsel, pursuant to Section 200.800 of the Illinois Commerce Commission's Rules of Practice (83 Ill. Adm. Code 200.800), and respectfully submit their Initial Brief in the instant proceeding.

I. INTRODUCTION

A. Overview

On June 5, 2009, the Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a Ameren CIPS, and Illinois Power Company d/b/a Ameren IP (collectively, "Ameren," "AIU," "AIUs," or "Company") filed with the Illinois Commerce Commission ("Commission") revised tariff sheets in which they proposed a general increase in electric and gas rates pursuant to Article IX of the Illinois Public Utilities Act ("Act" or "PUA"), 220 ILCS 5/9, to become effective July 20, 2009.

B. Procedural History

On July 8, 2009, the Commission suspended the filing to and including November 1, 2009, for a hearing on the proposed rate increase. On August 6, 2009, the cases were consolidated. On October 7, 2009, the Commission re-suspended the tariffs to and including May 1, 2010.

The following Staff witnesses have submitted testimony in this case: Theresa Ebrey (Staff Exs. 1.0 and 15.0), Mary Everson (Staff Exs. 2.0 and 16.0), Burma Jones (Staff Exs. 3.0 and 17.0), Richard Bridal (Staff Exs. 4.0 and 18.0R), Rochelle Phipps (Staff Exs. 5.0R and 19.0R), Janis Freetly (Staff Exs. 6.0 and 20.0), Peter Lazare (Staff Exs. 7.0 and 21.0), Philip Rukosuev (Staff Ex. 8.0), Cheri Harden (Staff Exs. 9.0 and 22.0), Christopher Boggs (Staff Exs. 10.0 and 23.0), Greg Rockrohr (Staff Exs. 11.0R and 24.0R), Eric Lounsberry (Staff Exs. 12.0 and 25.0), Brett Seagle (Staff Exs. 13.0 and 26.0R), and David Sackett (Staff Exs. 14.0 and 27.0R)

The following Petitions to Intervene were also granted in this matter: Citizens Utility Board ("CUB"); Grain & Feed Association of Illinois ("GFAI"); the Kroger Company; People of the State of Illinois ("AG"); AARP; Illinois Industrial Energy Consumers ("IIEC"); Constellation New Energy ("CNE"); Charter Communications, Inc.; System Council U-05 of the International Brotherhood of Electrical Workers, AFL-CIO ("IBEW"); Constellation NewEnergy-Gas Division, LLC ("CNE-Gas"); and the Cities of Champaign, Urbana, Decatur, Bloomington, and Town of Normal ("Cities").

An evidentiary hearing was held in this matter on December 14-17, 2009. In addition to all prefiled testimony and supporting affidavits being entered into evidence, Staff and the Company also agreed to admit Staff Group Exhibit 1, consisting of several stipulated Data Request ("DR") responses, and Staff Exhibit B, a stipulation between Staff and the Company regarding certain adjustments to operating expenses. The record was subsequently marked Heard and Taken. Appendices A, B, and C attached hereto include the Revenue Requirement Schedules proposed by Staff for the electric utilities, AmerenCILCO, AmerenCIPS, and AmerenIP, respectively. Appendices D, E, and F include the Revenue Requirement Schedules proposed by Staff for the gas utilities, AmerenCILCO, AmerenCIPS, and AmerenIP, respectively.

C. Nature of AIUs' Operations

D. Test Year

AIU proposed to use the twelve months ending December 31, 2008 with pro forma adjustments as the test year in this matter. No party objected to the use of this test year.

E. Legal Standard

All rates set by the Commission must be "just and reasonable" and any "unjust or unreasonable" rate is unlawful. In this regard, Section 5/9-101 of the PUA provides, in relevant part, that:

> All rates or other charges made, demanded or received by any product or commodity furnished or to be furnished or for any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge made, demanded or received for such product or commodity or service is hereby prohibited and declared unlawful. All rules and regulations made by a public utility affecting or pertaining to its charges to the public shall be just and reasonable. (220 ILCS 5/9-101)

F. Other Legal Issues

II. RATE BASE

A. Overview

B. Resolved Issues

1. Historical Plant Additions (2002-2006)

Staff witness Everson proposed adjustments to Plant in Service for 2002-2006 plant additions because support for the projects was either inadequate or missing. These projects had been previously disallowed by the Commission in prior rate cases because there was inadequate or missing documentation to support including the projects in rate base. (Staff Ex. 2.0, pp. 8-10) Staff's adjustment was accepted by the AIU. (Ameren Ex. 43.0, p. 3)

2. Plant Additions (2007-2008) Except For Pana East Substation

Staff and AIU agree on adjustments to 2007 – 2008 Plant Additions (except for Pana East Substation, discussed in Section II.C below), as presented in Staff Ex. 18.0R, Schedule 18.02, Ameren Ex. 29.8, and Ameren Ex. 29.16.[1] The agreed upon adjustments include:

- Corrections for seven easement-related transactions impacting only accumulated depreciation, accumulated deferred income taxes, and depreciation expense (Staff Ex. 18.0R, pp. 23-24); and
- Removal of specific transmission plant (Ameren Ex. 29.0 (Revised), p. 38).

[1] Staff witness Bridal proposed adjustments to reduce 2007-2008 Plant Additions as a result of his statistical sample review. (Staff Ex. 4.0, pp. 4-11) Staff witness Rockrohr proposed adjustments to remove specific transmission plant from IP Electric and IP Gas 2007-2008 Plant Additions. (Staff Ex. 4.0 p. 16; Staff Ex. 11.0R, pp. 10-12) AIU accepted, with modification, Staff witness Bridal's proposed adjustments to reduce 2007-2008 Plant Additions (Ameren Ex. 43.0, p. 6); AIU also accepted Staff witness Rockrohr's adjustments to remove transmission plant from IP Electric and IP Gas 2007-2008 Plant Additions. (*Id.*) In addition, AIU proposed additional adjustments to remove other associated, transmission operations-related plant from CILCO and CIPS 2007-2008 Plant Additions. (*Id.*, p. 38) Staff accepted the modified and additional adjustments proposed by the AIU. (Staff Ex. 18.0R, pp. 23-24; Staff Ex. 24.0R, p. 7)

Staff witness Greg Rockrohr reviewed several specific projects for which AmerenCILCO, AmerenCIPS, and AmerenIP included costs in their proposed electric rate bases. AIU's specific projects include one-time capital investments with costs greater than $100,000. Mr. Rockrohr explained that Section 9-211 of the PUA specifies that the Commission may only allow a utility's plant additions into rate base if the utility's investments in those plant additions are prudently incurred and the plant additions are used and useful in providing service to the utility's customers. (Staff Ex. 11.0R, pp. 3-4) For each specific project he reviewed, Mr. Rockrohr learned why the utility believed the project was needed, he learned about other alternatives the utility contemplated, and he learned about the costs associated with each contemplated alternative. In addition, Mr. Rockrohr considered whether the utility could appropriately allocate costs for the specific projects he reviewed to electric ratepayers in the manner the utility proposed. (*Id.,* p. 6) Based upon his review of several of AIU's most costly specific projects, Mr. Rockrohr recommended adjustments to AIU's rate base proposals. AIU and Mr. Rockrohr have reached agreement regarding the appropriateness of the utility's cost recovery for the Washington Street Office renovation project and transmission-related projects.

<u>AmerenCILCO's Washington Street Office Building Renovation</u>

Staff witness Rockrohr initially recommended that the Commission disallow $561,934 of AmerenCILCO's $749,950 total cost for a specific project identified as WO# 22913, which renovated an office building located on Washington Street, in Springfield. In conjunction with his recommendation in direct testimony, Mr. Rockrohr invited AIU to provide additional information and/or evidence in its rebuttal testimony to better explain and justify its proposed allocation of 75% of the total project costs to its electric ratepayers. (*Id.*, pp. 7-8) AIU witness Stafford responded by proposing a different allocation of project costs in his rebuttal testimony that was based upon the actual use of the renovated building, whereby 43.45% of the total project cost, or $325,853, would be allocated to electric ratepayers, and 24.4% of project costs, or $182,988, would be allocated to gas ratepayers. (Ameren Ex. 29.0, pp. 16-18) Mr. Rockrohr found Mr. Stafford's revised allocation proposal for project costs to be reasonable, and in rebuttal testimony recommended that the Commission allow AmerenCILCO to recover its costs for WO# 22913 in the manner Mr. Stafford proposed in his rebuttal testimony. (Staff Ex. 24.0R, p. 3)

<u>AIU's Transmission-Related Projects</u>

Staff witness Rockrohr recommended that the Commission disallow AmerenIP's proposed recovery of $1,476,315 for WO# 23159 because this specific project was a transmission project necessitated by North American Electric Reliability Corporation ("NERC") standards, and costs for the project should not have been included in this proceeding. Mr. Rockrohr stated in direct testimony that he might later adjust his recommendation to reflect the disallowance of additional amounts for other transmission-related projects. (Staff Ex. 11.0R, pp. 11-12) In response to Mr. Rockrohr's direct testimony, AIU agreed to remove the cost for WO# 23159 from AmerenIP's proposed rate base, and in addition, remove costs for two additional transmission-related projects that also were associated with NERC compliance: $129,958 for AmerenCILCO's WO# 23161, and $369,187 for AmerenCIPS' WO# 23160. (Ameren Ex. 33.0 (Revised), p. 3; Ameren Ex. 29.0 (Revised), p. 38) Mr.

Rockrohr agreed with AIU's rebuttal proposal to remove costs for all three transmission-related projects from the utilities' proposed rate bases. (Staff Ex. 24.0R, p. 7)

3. Liberty Audit Pro Forma Adjustment

Staff witness Everson proposed an adjustment to remove the pro forma plant additions related to the Liberty audit from rate base since the costs do not reflect known and measurable changes to plant. (Staff Ex. 2.0, pp. 10-11) The AIU withdrew its pro forma adjustment from the AIU's electric revenue requirement. (Ameren Ex. 29.0 (Revised), p. 26)

4. Lincoln Storage Field Sulfatreat

Staff initially recommended the removal of AmerenCILCO's costs associated with the installation of a fourth Sulfatreat vessel at the Lincoln storage field. Staff noted that AmerenCILCO failed to provide sufficient information to demonstrate that the project to install a new Sulfatreat vessel at its Lincoln storage field will be prudently incurred and used and useful. (Staff Ex. 13.0, p. 4)

In response to Staff concerns, Company witness Mr. Underwood provided additional information in his rebuttal testimony to support the prudence of used and usefulness of AmerenCILCO's decision to construct a fourth Sulfatreat vessel. Further, Staff conducted an on-site review of the Lincoln Storage field to verify a portion of the additional information Mr. Underwood provided in rebuttal testimony. The additional information alleviated Staff's concern and Staff no longer disputes AmerenCILCO's request to include costs associated with the installation of a fourth Sulfatreat vessel at its Lincoln Storage field in its rates. (Staff Ex. 27.0R, pp. 9-10)

5. Materials and Supply Inventory Except For Value of Gas in Storage (C.6. below)

For purposes of the immediate dockets only, by the stipulation dated December 14, 2009 and contained in Staff Exhibit B, AIU and Staff agree to reduce the General Materials and Supplies component of the total Materials and Supplies Balances by an accounts payable percentage of 10.53% based on payment lead days for the other O&M expense of Cash Working Capital and to reduce the Gas in Storage component of the total Materials and Supplies Balances by an accounts payable percentage of 6.63% based on payment lead days for PGA/Fuel expense of Cash Working Capital. (Staff Ex. B, p. 2) For the AIU electric utilities, Materials and Supplies Balances include only General Materials and Supplies. For the AIU gas utilities, Materials and Supplies Balances consist of two components: General Materials and Supplies and Gas in Storage.

The parties stipulated that the General Materials and Supplies percentage (10.53%) should be applied to the General Materials and Supplies amounts presented in each gas and electric Company's respective Schedule B-8.1, as presented in Ameren Ex. 51.10.

The balance to which the Gas in Storage percentage (6.63%) should be applied remains contested and is discussed further in Section II.C.6. below.

6. Gas Tapping Fee

AIU accepted Staff's proposed adjustment to Gas Tapping Fee, as presented in Staff Ex. 18.0R, Schedule 18.07. (Ameren Ex. 51.0 (2^{nd} Revised), p. 6) The adjustment corrected the Company's original calculations of its pro-forma Gas Tapping Fee

Adjustment impacts on Plant, Accumulated Depreciation, Accumulated Deferred Income Taxes, and Depreciation Expense.

7. Error Regarding A Sulfatreat Change Out

Ameren accepted Staff's proposed adjustment to correct an accounting error regarding a Sulfatreat change out. (Ameren Ex. 51.0 (Revised), pp. 5-6) The error was a duplicate charge to expense from a plant project. (Staff Ex. 17.0, pp. 9-10)

C. Contested Issues

1. Pro Forma Plant Additions (2009-2010)

The Commission should approve Staff's adjustment to disallow plant additions beyond February 2010 from rate base. Staff witness Everson accepted Pro Forma Plant Additions related to both specific and blanket projects that will occur through February 2010 since Ameren provided documentation that the projects were known and measurable. Those projects anticipated beyond February 2010 were disallowed in Staff's adjustment.

In addition, Staff did not oppose storm restoration costs resulting from the May 2009 "inland hurricane" that Ameren included in its revised pro forma adjustment. (Staff Ex. 16.0, pp. 4-5) The AIU concurred with Staff's proposed adjustments. (Ameren Ex. 51.0 (2nd Revised), p. 7)

Both IIEC and AG/CUB witnesses disagreed with the pro forma plant additions to the extent that the adjustment did not reflect accumulated depreciation on embedded plant in service as of February 2010 (IIEC Ex. 6.0-C, p. 15; AG/CUB Ex. 4.0, pp. 11-15) as will be discussed in the following section.

2. Accumulated Reserve for Depreciation

Both the IIEC and AG/CUB argue that the AIU's post-test year additions to plant in service are "overstated"[2]and "selective and one-sided."[3] To remedy this deficiency in the adjustment, both parties propose to reflect the known and measurable changes to accumulated depreciation reserve during the same time period the plant additions are expected to be placed in service[4], thus accurately estimating the change to the AIU's "net" plant investment. AIU witness Stafford argues that the IIEC and AG/CUB proposal merely restates the entire depreciation reserve without considering other elements of rate base. (Ameren Ex. 29.0 (Revised), p. 25) The IIEC and AG/CUB counter that the AIU's proposal violates the matching principle and overstates net plant investment. (IIEC Ex. 6.0-C, pp. 15-16; AG/CUB Ex. 4.0, pp. 11-12) AIU witness Stafford continues to take issue with rolling the accumulated depreciation reserve balance forward as he argues it would result in a mismatch between plant additions and the associated depreciation reserve. (Ameren Ex. 51.0 (2nd Revised), p. 17)

Staff did not provide written testimony on this issue; however, during cross-examination, Staff witness Ebrey provided comments regarding the mechanics of the revenue requirement and the relationships among its various components. (Tr., pp. 738-747, 800-803, December 17, 2009) Ms. Ebrey confirmed that as of February 2010 the amount of net plant on the AIU books would not reflect the amount of accumulated depreciation at the December 2008 level. Ms. Ebrey further stated that, for ratemaking purposes, the matching principle would require the alignment of all components of the revenue requirement including all components of rate base, cost of service and rate of

[2] IIEC Ex. 2.0-C, pp. 80-81.
[3] AG/CUB Ex. 2.0, p. 5.
[4] IIEC Ex. 2.0-C, pp. 86-87; AG/CUB Ex. 2.0 (Corrected), p. 5.

return information as of a consistent date. Finally, Ms. Ebrey concluded that the net plant as proposed by the AIU in this case would be higher than the net plant included in the utilities books at the end of February 2010.

This issue is about balancing "regulatory lag" (the AIU argument) with the "matching principle" (IIEC's argument). Regulatory lag is the theory that rates granted in a rate proceeding will lag behind ongoing costs[5] since costs could be expected to rise from the filing of a rate case until the final order in the rate case is issued and rates become effective. In addition, costs could also increase after the approved rates are actually in effect. To remedy the problem with regulatory lag, pro forma adjustments are allowed in the ratemaking process to include more current costs beyond the historic test year levels. However, there is a point in which the remedy for regulatory lag intentionally overstates anticipated costs as of at a certain point in time or during the time that rates would be in effect. The balance of net plant used to set rates in this case should not be greater than the anticipated actual net plant balance in February 2010 or during the time that rates from this case are expected to be in effect. Any overstatement of net plant would violate the matching principle and clearly go beyond the remedy for regulatory lag.

3. Plant Additions (2007-2008): Pana East Substation

Staff witness Rockrohr testified that he disagreed with AmerenCIPS' proposal to charge electric ratepayers 100% of AmerenCIPS' cost for two specific projects that were both initiated to facilitate the clean-up of coal tar contamination. Together, the two specific projects equated to approximately $2 million: $1,467,883 for WO# 16922, which

[5] For purposes of this discussion, "costs" include all amounts included in the development of a revenue requirement for ratemaking purposes to include all components of the revenue requirement.

relocated AmerenCIPS' Pana East Substation, and $532,268 for WO# 17954, which relocated the distribution and transmission lines entering and leaving Pana East Substation. Mr. Rockrohr explained that AmerenCIPS initiated these two projects to facilitate the clean-up of coal tar contamination, and not because the existing facilities were inadequate for the provision of electric service to customers. (Staff Ex. 11.0R, pp. 9-10)

In his direct and rebuttal testimony, AIU witness Pate confirmed that AmerenCIPS' reason for these two relocation projects was that AmerenCIPS identified a large area directly underneath the former Pana East Substation site that had been contaminated by gas and tar by-products that traveled along subsurface routes from CIPS' nearby former manufactured gas plant. Mr. Pate stated the contamination had to be removed per the regulations of the Illinois Environmental Protection Agency. (Ameren Ex., 6.0E (Revised), p. 30; Ameren Ex. 33.0 (Revised), p. 5)

AmerenCIPS' Schedule F-4 further describes the reason for the Pana East Substation relocation project as follows:

> Environmental services requested that this substation be relocated so that they could clean up the coal tar discovered below the old substation in 2005. Due to budget constraints the relocation of this substation was deferred from 2006 to 2007. Once the substation was relocated in 2007, the coal tar cleanup was completed in early 2008. (Ameren Ex. 6.2, p. 6)

AmerenCIPS' Schedule F-4 for WO# 16922 further states:

> Due to the nature and amount of coal tar discovered below the old Pana, East substation and the environmental risk posed by leaving the coal tar in-place. The (sic) Illinois Environmental Protection Agency cleanup regulations (known as TACO) required that the contamination be removed from the site. No other alternatives were feasible or practicable because of the regulatory requirement to remove "source" materials [coal tar]. (*Id.*)

Mr. Rockrohr explained that he understood the Environmental Protection Act to assign the cost liability of contamination clean-up to the causer of the contamination.

(Tr., p. 204, December 14, 2009) Indeed, Section 58.9 of the Environmental Protection Act assigns liability for the cost of the clean-up of contamination to the party or entity that caused the release, not to the party or entity that owns the property that was contaminated.[6] AmerenCIPS' Pana East Substation did not cause or release the contamination, nor did AmerenCIPS' electric ratepayers. Therefore, it would be inappropriate for AmerenCIPS to recover from electric ratepayers 100% of its costs for the relocation, which occurred to facilitate the coal tar contamination cleanup. Mr. Rockrohr pointed out that if AmerenCIPS needed to relocate a customer's home for contamination clean-up, AmerenCIPS would not charge the customer, or for that matter its electric ratepayers, all of the relocation costs. AmerenCIPS would instead appropriately allocate its costs for the relocation of the customer's home to its various lines of business, including its electric utility. No single line of business would pay 100% of the relocation cost. Similarly, costs associated with the relocation of Pana East Substation should be allocated to AmerenCIPS' various lines of business, since the relocation occurred to facilitate contamination cleanup. (Staff Ex. 24.0R, pp. 5-6)

Mr. Pate argued that Mr. Rockrohr's hypothetical scenario involving relocation of a customer's house is dissimilar to relocation of Pana East Substation, since the relocation of the substation was required in order to provide adequate and reliable electric service to customers during AmerenCIPS' clean-up activities, whereas a customer's relocated house would not be used and useful in the provision of electric service. (Ameren Ex. 50.0 (Revised), p. 10)

However, whether or not the newly relocated home or the newly relocated substation is used and useful in the provision of electricity should not be the only fact

[6] Section 58.9 of the Environmental Protection Act (415 ILCS 5/58.9)

considered when deciding who should pay for the relocation. Mr. Rockrohr's position is not based upon whether the substation at its new location is used and useful. Instead, his position is based upon the fact that AmerenCIPS' Pana East Substation was used and useful at its former location, and was providing adequate electric service to customers at that former location. (Ameren Ex. 50.1, Response to Ameren DR AIU-ICC 29.06)

AIU's response to Staff DR GER 6.03 clearly indicates that if a third party were to request that AmerenCIPS relocate existing electric distribution facilities for which AmerenCIPS had adequate property rights, AmerenCIPS would require the requesting party to pay the entire relocation cost. (Staff Ex. 11.0R, Attachment B) Staff agrees with AmerenCIPS' policy provided in response to Staff DR GER 6.03: that the third party, rather than electric ratepayers, should pay relocation costs when the utility's facilities are adequate and used and useful at the original location, and a relocation happens because the third party requested or needed the relocation. A similar situation occurred at Pana East Substation. AmerenCIPS relocated its facilities associated with Pana East Substation that were adequately providing service to its electric customers. The contaminated soil beneath the former Pana East Substation site did not conflict with this provision of electricity, was in no way caused by the substation, and if left in the ground, would not have affected the ability of the substation to provide adequate and reliable service to AmerenCIPS' customers in the future. In short, the Pana East Substation was used and useful at its former location.

Even though the Pana East Substation was used and useful at its former location, contamination from AmerenCIPS' manufactured gas plant migrated beneath the substation, and the Environmental Protection Act assigned clean up cost liability to

AmerenCIPS, not because AmerenCIPS owned the substation property that was contaminated, but rather because AmerenCIPS was the owner of the nearby manufactured gas plant that caused the contamination. (Tr., pp. 204-205, December 14, 2009) After relocating the Pana East Substation so that cleanup could occur safely, AmerenCIPS completed its coal tar cleanup activities at the former substation site, and allocated the costs associated with that cleanup to both its gas and electric ratepayers via its environmental riders: Rider EEA and Rider GEA. (Staff Ex. 24.0R, p. 6) In other words, AmerenCIPS did not allocate 100% of its labor costs for site clean-up to its electric ratepayers: it instead allocated those cleanup costs between multiple lines of business. (Ameren Ex. 50.0 (Revised), p. 7) It remains a mystery to Staff why AmerenCIPS is unwilling to similarly allocate its labor charges for relocating the Pana East Substation rather than charge its electric ratepayers 100% of the cost for that relocation.

In summary, after reviewing the two specific projects associated with the relocation of the Pana East Substation to facilitate coal tar clean-up, Mr. Rockrohr did not object, generally, to AmerenCIPS' recovery of the relocation costs. Mr. Rockrohr became concerned, however, about AmerenCIPS' proposal to allocate 100% of its cost recovery to only its electric ratepayers, and AmerenCIPS' refusal to modify this allocation proposal. (Staff Ex. 24.0R, pp. 4-6) Mr. Rockrohr concluded that it would be more reasonable for AmerenCIPS' shareholders to bear some of the cost for relocating its Pana East Substation and associated facilities than it would be to allocate 100% of the costs for this relocation to AmerenCIPS' electric ratepayers as AmerenCIPS continues to propose. (Ameren Ex. 50.2, Response to Ameren DR AIU-ICC 29.04)

4. Hillsboro Storage Field – Used and Useful

The Hillsboro storage field is not operating in the same manner that it was when AmerenIP expanded the field and placed the costs associated with the expansion into its base rates in Docket No. 93-0183. (Staff Ex. 12.0, pp. 18-20) Given the manner in which AmerenIP is currently operating the Hillsboro storage field, it is no longer 100% used and useful at providing service to AmerenIP's customers. Staff calculated a used and useful percentage for the field to equal 96.01% and recommends the Commission use this value to set the Company's rates in this proceeding. (*Id*., p. 17)

Used and Useful Requirements

Section 9-211 of the Act contains the used and useful requirements regarding utility rates. Section 9-211 of the Act states as follows:

> The Commission, in any determination of rates or charges, shall include in a utility's rate base only the value of such investment which is both prudently incurred and used and useful in providing service to public utilities customers. (220 ILCS 5/9-211)

The Act also provides a definition of used and useful in Section 9-212 that states:

> A generation or production facility is used and useful only if, and only to the extent that, it is necessary to meet customer demand or economically beneficial in meeting such demand. (220 ILCS 5/9-212)

Further, AIU has an obligation to its customers to provide "…adequate, efficient, reliable, environmentally safe and least-cost public utility services which accurately reflect the long-term cost of such services and which are equitable to all citizens." (220 ILCS 5/1-102) As part of that obligation, AIU is responsible for maintaining its storage fields in an appropriate manner. As enumerated below, AIU failed to maintain its Hillsboro storage field in an appropriate manner. As such, ratepayers should not be required to continue paying for the Hillsboro storage field as if it were operating at 100%

used and useful when, in reality, the Hillsboro storage field is not operating in that fashion.

Past Used and Useful Adjustment

The Commission has previously addressed and adopted a used and useful adjustment regarding the Hillsboro storage field. Specifically, in Docket No. 04-0476, the Commission's Order in that proceeding indicated, in part, that:

> Based on its review of the record and of the arguments of Illinois Power and Staff, the Commission concludes that the Hillsboro Storage Field should be found to be 53.44% fully used and useful for purposes of this case, and that Staff's proposed used and useful adjustment should be adopted. The Commission finds that the economic benefits Staff assigned to the Hillsboro storage field's peak day and seasonal capacity are reasonable and appropriate to use in determining the used and usefulness of the Field. (Order, Docket No. 04-0476, May 17, 2005, p. 41)

Staff also noted that AmerenIP appealed the Commission's decision which found its Hillsboro storage field only 53.44% used and useful to the Appellate Court. The Appellate Court, on October 2, 2006, affirmed the Commission's decision.[7] (Staff Ex. 12.0, p. 21)

Current Used and Useful Calculation

Staff methodology in the instant proceeding followed the same methodology accepted by the Commission and confirmed by the Appellate Court in Docket No. 04-0476. Specifically, Staff's used and useful calculation was based on splitting the value of the Hillsboro storage field into two components – peak day capacity and seasonal price variation. Staff then determined that the value of the Hillsboro storage field came 79.70% from peak day capacity and 20.30% from seasonal gas costs savings. Staff used these values as allocation percentages within the used and useful calculation. Next, Staff used the Hillsboro storage field's three-year historical average, years 2006

[7] The decision was issued as an unpublished Rule 23 Order.

through 2008, of the amount of peak day capacity and working gas inventory available to ratepayers to determine the used and useful percentages for the field. This calculation provided a used and useful amount of 96.01%. (*Id.*, pp. 27-32) AmerenIP has not disputed the mechanics of Staff's used and useful calculation, but has disputed the need to make any used and useful disallowance at all.

<u>Historical Hillsboro Orders</u>

In Docket No. 91-0499, the Company received a certificate of public convenience and necessity for its expansion of the Hillsboro storage field. The Commission's Order in that proceeding noted the following:

> Mr. Brodsky testified that the Project will increase the total working gas inventory of the Hillsboro Storage Field from 3.1 billion cubic feet ("BCF") to 7.6 BCF, the injection rate to the Storage Field from 13,000 thousand cubic feet ("MCF")/day to 40,000 MCF/day, and the withdrawal or delivery rate from 50,000 MCF/day to 125,000 MCF/day. The Project is intended to increase Illinois Power's total storage capability by 42 percent, and to increase its total peak day storage withdrawal capability by 14 percent. Estimated gas-in-place after the Hillsboro Storage Field expansion will be 21.7 BCF, consisting of 7.6 BCF of inventory gas and 14.1 BCF of base gas. (Order, Docket No. 91-0499, October 21, 1992, p. 3)

In Docket No. 93-0183, the Company also received Commission authority to expand the Hillsboro storage field and to recover the cost of that expansion through its rates. In particular, the Commission stated as follows in its Order in Docket No. 93-0183:

> IP is expanding the capacity of its Hillsboro storage field in Montgomery County by 4.5 BCF and the daily withdrawal rate at the field by 75,000 million cubic feet ("MCF"). IP is also constructing a 62-mile pipeline from Hillsboro to Decatur and additional transmission facilities from Hillsboro to the Metro-East Area. The IP witnesses indicated in their rebuttal testimony that the Hillsboro Project was placed in service on August 31, 1993, with the exception of two new delivery/control stations being constructed near Arthur, Illinois, to enhance interconnections with major pipeline suppliers in the area. (Order, Docket No. 93-0183, April 6, 1994, p. 8)

The same Order also stated:

> …Finally, the Commission concludes that the Hillsboro Project will provide substantial net economic and other benefits to IP's customers; that the project is necessary in order for IP to provide adequate, efficient and reliable service to its customers at lowest cost, and that it should be considered used and useful upon being placed into operation. (*Id.*, pp. 11-12)

As a result of these orders, AmerenIP, with Commission approval, conducted an extensive expansion of the Hillsboro storage field to increase its peak day capability (now rated at 125,000 Mcf/day), and the volume of inventory maintained in the field, (7.6 Bcf of inventory gas and 14.1 Bcf of base gas). Further, the Commission had found the field to be 100 percent used and useful based upon those values in Docket No. 93-0183. (Staff Ex. 12.0, p. 24)

Staff also made a comparison of the current operation of the storage field to post-expansion levels at the Hillsboro storage field. Staff demonstrated, as reflected on Table 2 below, that the Hillsboro storage field has not operated near the levels discussed in Docket Nos. 91-0499 and 93-0183 since AmerenIP placed it into service for the winter season of 1993-1994. (*Id.*)

Table 2

Winter Season	Peak Day Rating 93-0183	Peak Day Rating Actual	Percentage of 93-0183 Rating	Volume to Cycle 93-0183	Actual Volume Cycled	Percentage of 93-0183 Rating
1993-1994	125,000	125,000	100.00	7,600,000	7,583,611	99.78
1994-1995	125,000	125,000	100.00	7,600,000	5,951,065	78.30
1995-1996	125,000	125,000	100.00	7,600,000	4,937,930	64.97
1996-1997	125,000	125,000	100.00	7,600,000	4,291,916	56.47
1997-1998	125,000	125,000	100.00	7,600,000	4,230,985	55.67
1998-1999	125,000	125,000	100.00	7,600,000	4,099,140	53.94
1999-2000	125,000	100,000	80.00	7,600,000	3,050,370	40.14
2000-2001	125,000	100,000	80.00	7,600,000	2,916,351	38.37
2001-2002	125,000	100,000	80.00	7,600,000	2,759,938	36.31

2002-2003	125,000	100,000	80.00	7,600,000	2,576,839	33.91
2003-2004	125,000	125,000	100.00	7,600,000	2,616,540	34.43
2004-2005	125,000	125,000	100.00	7,600,000	4,003,429	52.68
2005-2006	125,000	125,000	100.00	7,600,000	6,693,547	88.07
2006-2007	125,000	125,000	100.00	7,600,000	5,930,606	78.03
2007-2008	125,000	125,000	100.00	7,600,000	6,610,055	86.97
2008-2009	125,000	125,000	100.00	7,600,000	5,772,194	75.95

(*Id.*, p. 25)

Further, when the field does not operate according to its design parameters, AmerenIP passes any additional gas costs it incurs to make up for the problems at Hillsboro to ratepayers through its PGA rates. In essence, AmerenIP's customers have paid twice for some of the Hillsboro capacity. This occurs because AmerenIP charges its customers base rates that include the cost of the Hillsboro expansion and AmerenIP also charges these same customers for any additional gas cost resulting caused by the Hillsboro facility derating that are included in the PGA rates. (*Id.*, p. 19)

<u>Withdrawal Volumes</u>

AmerenIP noted in its more recent rate case, Docket Nos. 07-0585 – 07-0590 (Cons.), that the Hillsboro storage field was fully operational. AmerenIP also provided an analysis in that case that showed the volumes withdrawn from the Hillsboro storage field, after accounting for the weather as well as other extraneous events. According to this analysis, the gas withdrawal levels for the Hillsboro storage field were at or near the expected withdrawal levels. (*Id.*, pp. 21-22) AmerenIP indicated that various extraneous events impacted AmerenIP's ability to fully withdraw gas from the Hillsboro storage field in the recent 2006/2007 winter season. AmerenIP indicated that, excluding the temperatures experienced, it had addressed each of these events. (*Id.*)

However, it does not appear that Ameren resolved all of the problems at the storage field. To the contrary, the Hillsboro storage field has actually started to see a reduction in the seasonal withdrawal quantity. The Hillsboro storage field's withdrawal volumes are not back to the full operating capacity of the field, namely, a seasonal withdrawal quantity of 7.6 Bcf. Further, as Table 3 shows below, winter season heating degree-days[8] actually experienced the last few years should not have caused any limiting factors for the withdrawals from the Hillsboro storage field. (*Id.*, pp. 25-26)

Table 3

Month	Normal	2006/2007	2007/2008	2008/2009
November	378	515	333	414
December	784	739	798	946
January	1090	841	1082	1207
February	1014	1145	1117	1122
March	811	860	942	757
Total	4077	4100	4272	4446

(*Id.*, p. 26)

In fact, Table 3 shows that the last several winter seasons have been significantly colder than normal. However, Table 2 (discussed earlier) shows that AmerenIP was only able to withdraw about 6.6 Bcf in the 2007/2008 winter season and only 5.8 Bcf in the most recent 2008/2009 winter season, even though overall these winters were colder than normal.

In fact, AmerenIP agreed that temperatures experienced in the winter season would impact the volume of gas withdrawn from storage and that more gas should be withdrawn in a colder than normal winter season than a warmer then normal winter season. (Tr., p. 391, December 15, 2009) Further, AmerenIP experienced the highest

[8] Heating degree days are quantitative measures designed to reflect the demand for energy needed to heat a home or business. Heating degree days are calculated by subtracting the average daily temperature from a base temperature, usually 65 degrees.

number of heating degree-days during the most recent winter season, 2008-2009, of the last five winter seasons. (*Id.*, p. 396) However, a review of Table 2, provided above, indicates that the gas withdrawn from Hillsboro during the most recent winter season was the lowest volume in the last four years. In other words, AmerenIP was unable to exceed its recent historical withdrawal levels from the Hillsboro storage field in its most recent winter season, 2008/2009, even though this period was the coldest winter season AmerenIP has experienced in the last five years.

<u>Current Operating Level</u>

AmerenIP indicated that it plans to operate the Hillsboro storage field at an annual withdrawal rating of 6.4 Bcf versus the 7.6 Bcf rated capacity. Further, AmerenIP indicated its recent inventory studies ("Hillsboro Study") supported this withdrawal level. (Staff Ex. 25.0, pp. 15-16) However, AmerenIP is not proposing to alter the ratio of gas within the Hillsboro storage field. (*Id.*, p. 16)

Staff responded by noting that while it did not disagree with AmerenIP's reasoning for operating Hillsboro in this manner, the reason it is necessary to operate the field a the lower withdrawal rating for a period of time is partially due to the prior measurement errors that AmerenIP experienced at the storage field. These measurement errors have necessitated further study of the field. In other words, the prior years of changing inventory volumes and the uncertainty that results from the multiple metering corrections has created a situation where AmerenIP needs additional time to study the Hillsboro storage field. The optimal method for conducting these studies is to operate the field at a consistent level. (*Id.*)

AmerenIP's current proposed operation of the Hillsboro storage field and its desire to operate it at a consistent level is partially the result of the prior issues that it had at the Hillsboro storage field. Essentially, due to the various inventory corrections that AmerenIP has made at its Hillsboro storage field, it has not been able to conduct inventory verification studies and now must spend additional time operating the field in a consistent manner in order to determine the current operating parameters of the Hillsboro storage field. (*Id.*, p. 24)

An AmerenIP report, dated November 20, 2006, indicated that as a result of replacing the 5.8 Bcf of inventory over the prior three years, the hysteresis curve is not stable enough to aid in determining a gas loss correction. AmerenIP personnel estimated that after three years of cycling the reservoir at a constant working gas volume, the reservoir would stabilize and the hysteresis curve will be helpful in quantifying gas loss volumes. (*Id.*, pp. 23-24)

Not only does AmerenIP need consistent operation of the Hillsboro storage field to allow the use of the hysteresis curve analysis, the past inventory problems also impact the use of the simulation model that AmerenIP relies on to review its field. When reviewing storage fields, the volume of gas within the field is an important assumption for the model. However, AmerenIP's prior measurement errors at the storage field caused uncertainty in the total inventory value of the field. Therefore, the constant operation of the storage field will also allow better analysis through the simulation model in the future. (*Id.*, p. 24)

In short, AmerenIP does not have a good handle on all of these facets of Hillsboro's operation at this time. This is partially due to AmerenIP's past problems with metering error causing inventory reductions at the field, which has kept AmerenIP from being able to operate the field in a consistent manner. Further, AmerenIP admitted the recent Hillsboro Study provided additional insight into the operation of the Hillsboro storage field, but it also identified additional areas to investigate. In other words, 16 years after the expansion of the field, AmerenIP still does not know why the Hillsboro storage field operates at its current levels or even if the original 7.6 Bcf rating is appropriate. This problem should not be borne by ratepayers. Instead, it is a function of prior problems that AmerenIP failed to identify in a timely fashion whose impact is still being felt today. (*Id.*, p. 28)

Therefore, Staff recommends that while AmerenIP spends the time it needs to determine the operating parameters of the Hillsboro storage field, the ratepayers should be kept whole by using the original specifications associated with the field, when determining whether or not it is used and useful. As such, based upon AmerenIP's inability to withdraw the original 7.6 Bcf rated capacity and its future intention to operate the Hillsboro storage field at an annual withdrawal rating of 6.4 Bcf, instead of 7.6 Bcf, Staff recommends that the Commission find the Hillsboro storage field to only be 96.01% used and useful.

Staff Ex. 1.0, Schedule 1.17 IP-G presents the adjustment to remove the non-used and useful portion of the Hillsboro Storage Field and the associated recoverable base gas from the Company's rate base, along with the associated accumulated depreciation and accumulated deferred income taxes.

In columns (j) and (k) of Schedule 1.01 for IP - Gas, Staff included in the revenue requirement a non-common equity return on the non-used and useful portion of the Hillsboro Storage Field because this is the ratemaking treatment the Commission has traditionally applied to prudently incurred but non-used and useful investments.

When the Commission made a used and useful adjustment to Illinois Power Company's Clinton Nuclear Power Plant, the Commission concluded:

> A used and useful determination is necessary in order to determine the appropriate costs of Clinton that should be borne by ratepayers. A number of proposals have been presented concerning the implementation of used and useful disallowances. The Commission must balance the interests of shareholders and ratepayers. If shareholders were to receive a profit on investment that is not used and useful, ratepayers would be unduly burdened. On the other hand, if investors do not at least receive a recovery of their reasonably incurred investment, they would be treated unfairly. The Commission concludes that the most equitable way to apportion the disallowance is to permit a return on the debt and preferred portion of all prudently incurred Clinton investment and the recovery of such investment, but to deny a return on the common equity portion of prudently incurred investment that is not used and useful. This determination will result in a denial of a common equity return on 72.8% of the prudently incurred Clinton costs. (Order, Docket Nos. 84-0055, 87-0695 and 88-0256 (Cons.), March 30, 1989, p. 151)

Columns (j) and (k) of Schedule 1.01 apply this same ratemaking treatment to the Hillsboro Storage Field by including a non-common equity return on the non-used and useful portion. The AIU did not address the presentation of Staff's adjustment in testimony, but only took issue with the merits of the adjustment.

5. Cash Working Capital

The Commission should approve the Cash Working Capital ("CWC") methodology and adjustment proposed by Staff. Staff witness Ebrey proposed adjustments to CWC proposed by the AIU to:

1. Use the Gross Lag Methodology rather than the Net Lag Methodology used by the AIU;
2. Use consistent expense lead days for other operations and maintenance expense for both the gas and electric utilities;
3. Use a revenue lag of zero days for pass-through taxes; and
4. Include service lead time in expense lead days for pass-through taxes. (Staff Ex. 1.0, p. 19)

The AIU accepted the first two of these changes in its rebuttal position. (Ameren Ex. 31.0, pp. 2-3) In addition, Staff accepted the presentation of bank facility fees and the expense lead time for those fees as presented in the Company testimony and exhibits.[9] Staff and the AIU agree that the expense levels ultimately included in the CWC analysis should reflect the Commission's position on income and expense levels in the Final Order.[10]

The remaining issues involving CWC address the treatment of revenue lag for pass-through taxes collected and the service lead associated with total expense lead days for revenue tax expense. Ameren witness Heintz states that "the issue at hand is the elapsed time between the receipt of a customer's payment and the remittance of the funds to the appropriate taxing authority."[11] This portrayal of the issue oversimplifies the lead-lag study. If Mr. Heintz's statement was correct, there would be no need to consider billing dates or periods of time for which the pass-through taxes apply. The analysis would be limited to comparing cash receipt dates and cash disbursement dates only. Staff points out this error in Mr. Heintz's analysis which purports to measure the time between receipt of funds for pass-through taxes and remittance of those funds to the taxing authorities. (Staff Ex. 15.0, pp. 14-15)

While the utility is liable for the payment of the pass-through taxes it collects from its customers, the utility does not have any investment related to pass-through taxes for which it is awaiting payment associated with that bill. For example, the Company has an investment in the amount of gas or power that was delivered which it needs to cover by the payment of the bill by the customer. There is no corresponding investment as it

[9] Ameren Ex. 29.1, Schedule 2, p. 4; Ameren Ex. 29.2, Schedule 2, p. 4; Ameren Ex. 29.3, Schedule 2, p. 4; and Ameren Ex. 31.0, p. 11.
[10] Ameren Ex. 31.0, p. 8.
[11] Ameren Ex. 31.0, p. 4.

applies to pass-through taxes billed.[12] AIU witness Heintz confirmed in testimony that "the AIU is reflecting that it has no out-of-pocket expense for which it is awaiting payment." (Ameren Exhibit 4.0E, p. 11) As the Companies acknowledge, they merely function as a collection agent for the taxing authorities. (Ameren Exhibit 4.0E, p. 11) Thus, the correct revenue lag for pass-through taxes is zero.

The AIU argument regarding the service lead time for expenses is inconsistent with Mr. Heintz's own definition. Mr. Heintz claims that the service lead time is "associated with the timing of the provisioning of service" and that if there is no service lag on the revenue side, there cannot be service lead on the expense side.[13] As Staff pointed out in direct testimony:

> The amounts related to pass through taxes accrue over a monthly or quarterly period and are remitted in most cases in the month after the end of the accrual period. Thus, the period of time over which the amounts are accrued is ignored in the AIU's calculation. To accurately reflect the lead time associated with the payment of pass-through taxes, the service lead time, measured as the mid-point of the accrual period, must be reflected in the weighted lead time calculation.[14]

Staff's proposed CWC methodology should be approved since Staff's treatment of pass-through taxes is more reasonable than the AIU treatment.

6. Working Capital Allowance for Gas In Storage

As discussed in Section II.B.5. above, AIU and Staff agree to reduce the Working Capital Allowance for Gas in Storage (Value of Gas in Storage) component of the total Materials and Supplies Balances by an accounts payable percentage of 6.63%. Staff's proposed valuation of Gas in Storage should be used in the calculation of the accounts payable adjustment. If the Commission should reject Staff's valuation of Gas in

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[12] An exception to this statement is the Illinois Gross Revenue Tax. Estimated payments are made on January 10, April 10, July 10 and October 10 with a true-up of amounts paid the following March 31.
[13] Ameren Ex. 31.0, p. 7.
[14] Staff Ex. 1.0, p. 23.

Storage, and accept the AIU valuation, the AIU amount for Gas in Storage presented in Ameren Ex. 51.10 should be used in the calculation of the accounts payable adjustment.

The only remaining issue involving AIU's requested working capital allowance for gas in storage for its gas utilities involves the gas price to apply to the gas volumes. Staff recommends the use of the 2009 gas price information, whereas AIU recommends the use of a three-year average to price this gas. As a result of this pricing difference, Staff recommends a reduction of $1,795,143 to AmerenCILCO's requested amount (Staff Ex. 25.0, Schedule 25.01 CILCO-G, l. 3), a reduction of $3,662,720 to AmerenCIPS' requested amount (*Id.*, Schedule 25.02 CIPS-G, l. 3), and a reduction of $12,255,211 to AmerenIP's requested amount (*Id*., Schedule 25.03 IP-G, l. 3). Staff has four reasons for its recommendation. These reasons are:

1. Ameren's proposal lacks consistency;
2. Ameren's proposal relies on outlier 2008 gas prices;
3. 2009 actual prices include impact from 2008; and
4. 2009 prices are representative of future gas costs. (*Id.*, p. 10)

<u>Consistency</u>

Staff's proposed pricing methodology is consistent with the methodology from the Commission's Order in Docket Nos. 07-0585 – 07-0590 (Cons.) for this same issue. Specifically, AIU in its 2007 rate case proposed to value each of its gas utilities' requested working capital allowance for gas in storage by using actual 2008 data, when known, its in-place gas hedged prices in 2008, and the NYMEX strip prices for those periods when actual information was not available. (*Id*., p. 9) The Commission accepted AIU's pricing methodology. (Order, Docket Nos. 07-0585 – 07-0590 (Cons.), September 24, 2008, pp. 77-78)

AIU Proposal Relies on Outlier 2008 Gas Prices

AIU's proposal to average the 2007-2009 gas prices to value its gas utilities' requested working capital allowance for gas in storage amounts allows Ameren to place partial reliance on the gas prices it experienced in 2008 within its calculation. The 2008 gas prices were the highest prolonged prices for natural gas that the industry has experienced during the Staff witness' 20+ years at the Commission. (Staff Ex. 25.0, p. 10) The AIU did not dispute this fact.

A review of the gas prices that AIU provided, as well as the NYMEX future prices, demonstrates that the 2008 gas prices were outliers. Table 1, below, shows the WACOG[15] prices for the years 2007-2009 and the gas price average that AIU proposes to use. Table 1 indicates that the 2008 gas prices are out of line with the other years and AIU's reliance on those values causes a significant increase in the average price that AIU advocates. (*Id.*, p. 11)

Table 1

AmerenCILCO		AmerenCIPS		AmerenIP	
Year	Price ($/Dth)	Year	Price ($/Dth)	Year	Price ($/Dth)
2007	6.688	2007	6.477	2007	7.428
2008	**8.504**	2008	**8.335**	2008	**8.903**
2009	6.406	2009	6.128	2009	6.466
Average	7.141	Average	6.932	Average	7.582

Source: Ameren Exhibit 45.1 (emphasis added)

[15] WACOG = Weighted average cost of gas.

Further, a review of the NYMEX gas future prices (based on November 2, 2009 values) for the coming years shows that the market place does not currently expect the forward gas prices to return to the gas price levels experienced in 2008. Specifically, the average price of NYMEX futures for 2010 and 2011 are $5.51/Dth and $6.50/Dth, respectively. This supports Staff's conclusion that the 2008 gas prices that Ameren experienced are price outliers. (*Id.*)

Finally, since ratepayers already experienced those high gas costs through their 2008 gas bills, it is not fair to require the customers to continue paying these higher gas costs when there is no indication that gas costs will return to those levels in the near future. (*Id.*)

<u>2009 Gas Prices Include Impact From 2008</u>

Staff admits that the 2009 gas costs include several months of data with gas prices that are significantly lower than those experienced by AIU in 2008. However, the 2009 gas cost calculation is based on the 13-month average of the month ending values from December 31, 2008 through December 31, 2009. This means that a portion of the 2009 gas costs includes gas volumes and values from natural gas that AIU injected into storage during 2008. Therefore, the 2009 gas cost calculation would have several months of data, namely, December 2008, January through March or April 2009 (depending on the specific characteristics of the leased storage service or on-system storage field) whose gas prices are primarily based on the higher than normal prices from 2008. Therefore, while 2009 gas prices dropped significantly, these much lower gas prices were offset within Ameren's WACOC calculation by the much higher 2008 gas prices that remained in the 2009 calculation. In other words, the gas prices that make up the 2009 average are a combination of both high and low gas prices and, as a result, the 2009 prices provide a reasonable proxy for the gas costs that AIU may experience once its rates go into effect. (*Id.*, pp. 12-13)

2009 Gas Prices are Representative of Future Costs

Staff noted that while no one knows with certainty what the future price of gas will equal, the NYMEX futures contracts provide an indication of the gas market's expectations for future prices. Those future prices show that the average NYMEX future prices for 2010 are lower than the 2009 gas costs recommended by Staff and that the average 2011 NYMEX future prices track very closely with the 2009 gas cost. Staff also noted that the AIU gas utilities have locked in some of the lower gas prices that existed in 2009 through its hedging activity for 2010 (and beyond). Specifically, for the storage injection months, roughly April through October, AIU has locked in a portion of its gas purchases, which will include some portion of the gas injected into storage. (*Id.*, p. 13) These values (provided as confidential values in Staff's testimony) show that the AIU's existing hedged positions for 2010 and 2011 are more in line with Staff's proposal to use the 2009 gas costs than AIU's proposal for a three-year average that includes the high gas prices from 2008. Therefore, going forward, the Staff proposed 2009 gas prices are much more representative of expected prices than Ameren's proposal.

Staff's recommendation is consistent with the Commission's prior AIU rate case order and uses a gas price that is consistent with the gas prices the market place expects to occur when AIU rates go into effect. Conversely, AIU's recommendation places too much reliance on the 2008 gas prices that Staff has shown are price outliers. Therefore, the Commission should accept Staff's recommendation for valuing AIU's working capital allowance for gas in storage for its gas utilities.

7. OPEB Net of ADIT (Accrued OPEB Liability)

The Commission should approve the adjustments to reflect the impact of the Other Post Employment Benefit ("OPEB") liabilities in the calculation of the AIU's rate bases as proposed by Staff and the intervenors. The OPEB liabilities represent ratepayer supplied funds and should be reflected as a reduction to rate base. This is consistent with the last two AIU rate case proceedings, where the Commission approved the reduction to rate base for accrued OPEB liabilities. (AG/CUB Ex. 2.0 (Corrected), pp. 6-7) Staff reflected those adjustments in the rebuttal revenue requirements for each AIU. Ameren witness Stafford proposed in rebuttal testimony that since only AmerenIP tracked the specific rate payer dollars when funding the liability (through March 2005), he was able to determine the portion of the AmerenIP liability not funded by ratepayers. (Ameren Ex. 29.0 (Revised), pp. 39-40)

During cross-examination, the AIU tried and failed to illustrate that funds collected from ratepayers could be tracked to specific cost of service line items. Staff witness Ebrey explained that ratepayers are paying a rate based on an overall level of cost of service and that the rates are not tied specifically to any certain line item in the revenue requirement. Therefore, such an analysis would not be possible. (Tr., pp. 767-772, December 17, 2009)

The AIU next attempted to draw a comparison to Ms. Ebrey's proposal in the AIU uncollectibles Rider proceeding, Docket No. 09-0399. However, Ms. Ebrey explained that there are a number of significant differences that make such a comparison invalid:

1. There is a direct connection between the amounts of uncollectible expense included in the revenue requirement to the pro forma revenues approved in the rate case. This was discussed in testimony in Docket No. 09-0399 and is also apparent in this case through the use of the schedule depicting the Gross Revenue

Conversion Factor ("GRCF"). (See Staff Ex. 15.0, Schedule 15.06 for each AIU) This is not the case with OPEB costs because OPEB costs do not vary with the level of revenues.

2. New provisions under Public Utility Act 96-0033, effective July 10, 2009 provided for the recovery of uncollectible expense through both base rates and through the rider mechanism. Sections 16-111.8(c) and 19-145(c) of the PUA mandate that the Commission "verify that the utility collects no more and no less than its actual uncollectible amount in each applicable FERC Form 1 reporting period." In order for the Commission to comply with the statute, it was necessary to establish a method to track the recovery of uncollectible expense. This is not the case with OPEB costs because OPEB costs are only recovered in base rates.

Staff's position is supported by the Commission in its Final Order in a prior AIU rate proceeding in Docket Nos. 06-0070/06-0071/06-0072 (Cons.) that came to the same conclusion that AG/CUB and Staff propose in this case:

> Ameren shows on its books an accrued liability for excess funds contributed for OPEB. While Staff and the AG indicate that each company's rate base should be reduced by the amount of this excess, as it reflects an excess of contributions by ratepayers, Ameren contends that the excess actually results from payments by Ameren. Staff believes that it is improper to single out any particular component of the cost of service and analyze that item in isolation, as it contends Ameren is doing in this case.
>
> The Commission agrees with Staff and the AG's analysis to remove these amounts from each utility's rate base. To look at this item in isolation from the other components of the cost of service, as Ameren attempts, and to then believe that the excess is solely attributable to Ameren is inappropriate. Ratepayers are not paying this cost of service as a separate line item, and it is inappropriate to treat it as such. The AG also notes other Commission decisions which have analyzed this issue, where it has been determined that as long as the company continues to control the ratepayer supplied OPEB funds, this deduction should be recognized in rate base. (See Docket No. 95-0219) Ameren has failed to provide any reason why the Commission should deviate from this position. The Commission therefore will reduce CILCO's rate base by $28,659,000, CIPS' rate base by $2,740,000, and IP's rate base by $1,217,000. (Order, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), November 21, 2006, p. 27)

The evidence demonstrates that the OPEB liabilities represent ratepayer supplied funds. Consistent with its findings in prior AIU rate cases, the Commission should accept the same adjustment in the current cases.

8. Other

D. Recommended Rate Base

Based on the rate bases for the electric and gas utilities originally proposed by CILCO, CIPS, and IP and Staff's proposed adjustments to those rate bases as summarized above, the electric utility rate base proposed by Staff for CILCO is $308,454,000, for CIPS is $530,832,000, and for IP is $1,461,873,000. The gas utility rate base proposed by Staff for CILCO is $191,987,000, for CIPS is $195,421,000, and for IP is $512,245,000. The rate bases are summarized as follows:

1. Electric

Staff Recommended Rate Bases
(In Thousands)

Description	CILCO	CIPS	IP
Gross Plant In Service	$859,211	$1,394,742	$2,392,689
Accumulated Depreciation	(466,910)	(747,441)	(745,378)
Net Plant	$392,301	$647,301	$1,647,311
Additions to Rate Base:			
Cash Working Capital	514	1,485	(1,115)
Materials & Supplies Inventory	4,740	9,980	15,909
CWIP Not Subject to AFUDC	189	140	16
Plant Held for Future Use	0	376	0
Deductions From Rate Base:			
Customer Advances	(5,853)	(3,345)	(17,579)
Accumulated Deferred Income Taxes	(60,193)	(112,832)	(158,209)
Customer Deposits	(3,167)	(8,500)	(9,489)
Accrued OPEB Liability	(20,077)	(3,774)	(14,971)
Electric Rate Base	$308,454	$530,832	$1,461,873

2. Gas

Description	**CILCO**	**CIPS**	**IP**
Gross Plant In Service	$533,803	$407,039	$991,303
Accumulated Depreciation	(356,798)	(197,382)	(507,238)
Net Plant	$177,005	$209,657	$484,065
Additions to Rate Base:			
Cash Working Capital	5,303	2,466	6,968
Materials & Supplies Inventory	43,100	28,041	75,132
CWIP Not Subject to AFUDC	12	0	0
Gas Stored Underground – Non-current	0	0	(422)
Deductions From Rate Base:			
Customer Advances	(3,535)	(1,115)	(16,954)
Accumulated Deferred Income Taxes	(10,685)	(40,133)	(23,152)
Customer Deposits	(3,678)	(1,809)	(4,501)
Accrued OPEB Liability	(15,535)	(1,686)	(8,891)
Gas Rate Base	$191,987	$195,421	$512,245

III. OPERATING REVENUES AND EXPENSES

A. Overview

B. Resolved Issues

1. Annualized Labor

Staff witness Ebrey proposed an adjustment to limit the annualized labor to be included in base rates to those pay increases that meet the known and measurable criteria. (Staff Ex. 1.0, pp. 23-25) The AIU accepted this adjustment. (Ameren Ex. 29.0 (Revised), p. 6)

2. FICA Corrections

Staff witness Ebrey proposed an adjustment to make corrections to the FICA adjustments proposed by the AIU. (Staff Ex. 1.0, pp. 26-27) The AIU accepted this adjustment. (Ameren Ex. 29.0 (Revised), p. 6)

3. Outside Professional Services

Ameren accepted Staff's proposed adjustment to remove the fees paid to Jacobs Consultancy, Inc. to perform an electric utility workforce analysis study for the Ameren Illinois Utilities. (Ameren Ex. 29.0 (Revised), p. 6) The legislation that mandated the study, Section 4-602 of the PUA, expressly prohibits recovery of the costs. (Staff Ex. 3.0, pp. 4-5)

4. Bank Facility Fees

Ameren accepted Staff's proposed adjustment to remove bank facility fees from operating expense. (Ameren Ex. 29.0 (Revised), p. 6) Staff considers the fees a cost of short-term debt and addressed them in that context. (Staff Ex. 5.0R, pp. 10-13)

5. Uncollectibles Expenses

Staff witness Ebrey proposed adjustments to the Uncollectibles Expenses proposed by the AIU since in her opinion, the use of estimated 2009 data did not meet the known and measurable criteria. (Staff Ex. 1.0, p. 27) In rebuttal, the AIU proposed to base its uncollectibles percentages on the 2007, 2008 and year to date 2009 actual data. (Ameren Ex. 29.0 (Revised), p. 10) Staff accepted this revised proposal. (Staff Ex. 15.0, p. 7)

6. Storm Expenses

Staff and AIU agree on adjustments to Storm Expenses as presented in Ameren Ex. 29.12. (Ameren Ex. 51.0 (2^{nd} Revised), p. 6)

AIU accepted Staff's proposed methodology to normalize Storm Expenses over a six-year period. However, AIU modified Staff's approach by using Storm Expenses from January 1, 2004 through September 30, 2009, rather than from January 1, 2003 through December 31, 2008. The modified AIU adjustment does not include any 2009 storm expense that may be realized after September 2009. (Ameren Ex. 29.0 (Revised), p. 28) Storm Expense is no longer at issue, as the parties have accepted the modified approach presented by the AIU. (Ameren Ex. 51.0 (2nd Revised), p. 6)

7. AMR Expense

Ameren accepted Staff's proposed adjustment to remove conversion costs and non-recurring costs in the test year associated with the AIU Automated Meter Reading ("AMR") upgrade. (Ameren Ex. 29.0 (Revised), p. 6) The costs were removed in order to reflect a normal, ongoing level of AMR expense in the revenue requirement. (Staff Ex. 3.0, p. 6)

8. Smart Grid Costs

Staff and AIU agree on adjustments to Smart Grid Costs, as presented in Staff Ex. 4.0, Schedule 4.09. (Ameren Ex. 29.0 (Revised), p. 6) The adjustments reduced AIU Smart Grid Costs pro-forma adjustment as a result of changes in scope of Phase 2 of the project, as well as removed incremental costs that are not known and measurable.

9. Homer Works HQ Sale

Staff and AIU agree on adjustments to Homer Works HQ Sale, as presented in Staff Ex. 18.0R, Schedule 18.05. (Ameren Ex. 51.0 (2nd Revised), p. 6) The adjustments updated the AIU Homer Works HQ Sale pro-forma adjustment from estimated amounts to actual amounts.

10. Social and Service Club Dues

Staff and AIU agree on adjustments to Social and Service Club Dues, as presented in Staff Ex. 4.0, Schedule 4.07. (Ameren Ex. 29.0 (Revised), p. 6) The adjustments removed social and service club membership dues.

11. Charitable Contributions

Staff and AIU agree on adjustments to Charitable Contributions, as presented in Ameren Ex. 29.13. (Staff Ex. 18.0R, p. 26) The adjustments removed certain contributions to community and economic development organizations from each Company's revenue requirement.

12. Industry Association Dues

Staff and AIU agree on adjustments to Industry Association Dues, as presented in Ameren Ex. 51.12. (Ameren Ex. 51.0 (2nd Revised), p. 23) The adjustments removed certain industry association dues attributable to lobbying activities.

13. Advertising Expense

Staff and AIU agree on adjustments to Advertising Expense, as presented in Ameren Ex. 29.15. (Ameren Ex. 29.0 (Revised), pp. 37-38) The adjustments removed expenses recorded in accounts 930 and 930.01 that were promotional, political, institutional, or goodwill in nature.

14. Customer Service and Information Expenses

Staff and AIU agree on adjustments to Customer Service and Information Expenses, as presented in Staff Ex. 18.0R, Schedule 18.04. (Ameren Ex. 51.0 (2nd Revised), p. 6) The adjustments removed certain customer service and information expenses which are promotional or goodwill in nature.

15. Lobbying Expense

Staff and AIU agree on adjustments to Lobbying Expense, as presented in Staff Ex. 18.0R, Schedule 18.01. (Ameren Ex. 51.0 (2nd Revised), p. 6) The adjustments removed lobbying expenses.

16. Rate Case Expense

Staff and AIU agree on adjustments to Rate Case Expense, presented in Ameren Ex. 30.4. (Staff Ex. 18.0R, p. 27)

In light of the requirement for the Commission to expressly address rate case expense in its final order, as imposed by Section 9-229 of the Act (220 ILCS 5/9-229), and in order to provide a more complete record regarding rate case expense, Staff attached to its direct and rebuttal testimonies the Companies' response to Staff DR RWB 13.02. This DR response provides rationale for the Commission to assess and determine that the amounts proposed to be expended to compensate attorneys or technical experts to prepare and litigate the instant proceeding are just and reasonable. Having reviewed the Companies' responses, Staff recommends that the Commission expressly state in its order that the proposed amounts to be expended by the Companies for rate case expense in this proceeding, as adjusted by Staff, are just and reasonable.

17. Collateral Expense

Staff withdrew a proposed adjustment to disallow interest expense associated with collateral posting for gas purchases. (Staff Ex. 17.0, pp. 4-5) Staff proposed the adjustment because Ameren testimony in the previous rate proceedings, Docket No. 07-0585 et al. (Cons.), indicated that such costs would remain necessary until the AIU carry investment-grade ratings, which they now do. (Staff Ex. 3.0, p. 9) Ameren witness Michael O'Bryan explained that the ratings are at the lowest investment grade notch for the purposes of many of AIU's contracts, so the AIU continue to have collateral postings in place with their counterparties. (Ameren Ex. 37.0 (Revised), p. 10) Because the AIU continue to incur costs for the collateral postings, which the Commission found in the previous rate proceeding are appropriate to pass on to ratepayers through base rates, Staff withdrew the adjustment. (Staff Ex. 17.0, pp. 4-5)

18. Company-Use and Franchise Gas

Staff initially recommended an adjustment to the gas costs used to calculate the company-use and franchise gas costs for all of the Ameren Gas Utilities. Staff also recommended that AIU normalize company-use and franchise gas volumes for the test year. Staff noted that the gas pricing AIU used in its initial filling was not an accurate representation of current gas prices, and as such, greatly overstated the value of gas. (Staff Ex. 13.0, pp. 26-27, 31)

In response to Staff concerns, AIU witness Mr. Wichmann agreed with Staff's position regarding gas pricing utilized in the calculation of company-use and franchise gas costs and provided a revised calculation for the test year using the most up-to-date pricing available for the price of natural gas. Additionally, Mr. Wichmann provided weather normalized volumes for use in the calculation of company-use gas costs. (Ameren Ex. 30.0, pp. 5-6) Staff did not dispute the AIU revised calculations of company-use and franchise gas costs. (Staff Ex. 27.0R, pp. 7-8)

19. Real Estate Taxes

Staff and AIU agree on adjustments to reduce CIPS Gas Real Estate Taxes, as presented in Staff Ex. 4.0, Schedule 4.14. AIU were silent regarding this adjustment in their narrative rebuttal testimony, but include the adjustment in the rebuttal revenue requirement for CIPS Gas. (Ameren Ex. 30.2, Schedule 1, p. 5) Also, in response to Staff DR RWB 22.02, AIU acknowledged acceptance of this adjustment. The adjustment adjusted CIPS Gas real estate taxes to remove amounts which represent prior period adjustments.

20. Prior Period HMAC

Staff witness Ebrey proposed an adjustment to remove 2007 HMAC costs from the revenue requirement for AmerenIP. (Staff Ex. 1.0, p. 30) The AIU accepted this adjustment. (Ameren Ex. 29.0 (Revised), p. 6)

C. Contested Issues

1. Tree Trimming

Staff proposed an adjustment to normalize tree trimming expense in the test year based on the actual amount of tree trimming expense incurred by each AIU for the time period January 2005 through June 2009. (Staff Ex. 3.0, p. 7) Ameren's vegetation management programs are based on maintaining a 4-year trim cycle, but the amount of work and associated costs to maintain that cycle vary from year to year. (*Id*.) For example, while trimming is planned for 24% of the total AIU system in 2010, the percentages for each AIU vary from 33% to 17%, based on number of circuits, or from 28% to 19%, based on number of circuit miles. An AIU would not need to trim 28% of its circuit miles each year to maintain a 4-year cycle, nor could a Company that trims only 19% of its circuit miles each year maintain a 4-year cycle. The average of costs incurred by each utility over a period of time smoothes the cost variances and provides a reasonable amount of tree trimming expense to include in the respective revenue requirement. (Staff Ex. 17.0, p. 7)

Ameren claims that Staff's recommended level of expenditure for tree trimming will be less than the amounts required to cover the AIU's costs to achieve the 4-year tree trimming cycle requirement across their entire service territories. (Ameren Ex. 26.0 (Revised), pp. 11-12) Ameren cites compliance with 4-year trim cycles, the inclusion of expanded reliability enhancement programs such as "cycle buster" and "prescriptive tree trimming," and wage increases as the reasons its proposed test year tree trimming expense exceeds historical average costs. (*Id*., p. 7) However, the AIU have been on 4-year trim cycles since 2004; mid-cycle patrols began in 2004 for AmerenCILCO and AmerenCIPS and 2005 for AmerenIP; and prescriptive trimming began in October 2006 for all three companies. Ameren made no claim that the amount spent for tree trimming in the period from which Staff calculated an annual average, updated to 2008 dollars, was not sufficient for each utility to meet its tree trimming obligations. (Staff Ex. 17.0, p. 9)

Ameren takes exception to the historical time period that Staff used to calculate an average annual amount for tree trimming expense on the basis that it is too far removed from the time that rates will become effective. (Ameren Ex. 26.0 (Revised), p. 6) The lag that exists between historical periods and the time rates go into effect is a normal consequence of filing an historical test year, which is the type of test year filed by Ameren. A company wishing to avoid the lag can choose to file a future test year. (Staff Ex. 17.0, p. 8)

Ameren attempted to compensate for the lag with pro forma adjustments based on the 2010 tree trimming budget for each AIU. Regarding pro forma adjustments, 83 Ill. Adm. Code 287.40 states as follows:

> These adjustments shall reflect changes affecting the ratepayers …where such changes occurred during the selected historical test year or are reasonably certain to occur subsequent to the historical test year within 12 months after the filing date of the tariffs and where the amounts of the changes are determinable.

While a budget may reflect an expected change in operating results, it does not reflect a known and measureable change in operating results. Therefore, Ameren's adjustments do not meet the "known and measurable" criteria and are inappropriate for pro forma adjustments to a historical test year. (Staff Ex. 3.0, p. 8)

For ratemaking purposes, the average annual amount of tree trimming expense calculated by Staff for each AIU approximates a more normal level of expense than does the amount spent in any one year and should be adopted by the Commission. (Staff Ex. 3.0, p. 7)

2. Incentive Compensation Expenses

The Commission should approve Staff's proposal to disallow the AIU proposed amounts for Incentive Compensation ("IC") because:

1. Costs disallowed in prior rate case proceedings remain in the Companies' proposals;
2. Costs associated with financial goals remain in the Companies' proposals; and
3. Costs which have not been shown to result in net benefit to ratepayers remain in the Companies' proposals. (Staff Ex. 1.0, p. 9)

The AIU accepted the portion of Staff's adjustment to remove previously disallowed capitalized incentive compensation costs from the test year rate base proposed by the AIU. However, they continue to oppose the adjustments to remove 1) costs associated with key performance indicators ("KPIs") for O&M Budget Compliance and Capital Budget Compliance and 2) costs which have not been shown to result in net benefit to ratepayers.[16]

The AIU acknowledge that the Commission did not allow costs associated with KPIs related to budget compliance in the prior rate cases. Nevertheless, the AIU recycle the same argument:

> The establishment and focus on budget targets provides benefits to ratepayers by setting a goal for managing overall expenditures for projects and services within a defined time period. Cost management/cost control is beneficial to customers to assure dollar resources are spent on priority initiatives and within the desired timeframes. This helps assure that customers receive quality service in the most cost-effective manner.[17]

This argument merely restates what the ratepayers already expect from their utility: "quality service in the most cost-effective manner." What the AIU fail to acknowledge is that "cost management/cost control" is of equal, if not greater, benefit to their shareholders, thus making it more in line with the KPI related to earnings per share which the AIU have already removed from their revenue requirements. The AIU failed to demonstrate how the budget compliance KPIs are based on anything other than financial related goals. Therefore, the costs related to those KPIs should be disallowed from recovery in the revenue requirement. (Staff Ex. 15.0, pp. 8-9)

The AIU offer Ameren Exhibit 42.1 as further information demonstrating the ratepayer benefits of the operational goals of the AIU's incentive plans. However, the exhibit merely describes what the KPIs are designed to do; the exhibit does not reflect the outcome or results of the performance of the goals, making it impossible to determine any benefit the ratepayers might gain from the goals being met. Even though

[16] Ameren Ex. 42.0, p. 2.
[17] Ameren Ex. 42.0, pp. 3-4.

the targeted goal might be reached, the expected outcome or benefit may not have been achieved or the benefit may in fact be less than anticipated when the goal was established. In the Companies' response to Staff DR TEE 8.05 (Staff Ex. 1.0 Attachment A), the Companies were unable to provide any **benefit** associated with the performance of those goals. (Staff Ex. 15.0, pp. 9-10)

Staff does agree that not all benefits that may be achieved are tied to financial measurement. Accordingly, Ms. Ebrey identified certain other KPIs for which she is allowing cost recovery. (*Id.*, p. 11)

Finally, Staff is disallowing all amounts allocated from AMS to the AIU for IC since a portion of those costs are tied to financial goals and the AIU did not demonstrate customer benefit resulting from the remainder of the goals. (*Id.*, p. 12)

3. Pension, OPEB and Major Medical Expenses (including Production Retiree Expenses)

The Commission should accept Staff's adjustment limiting pension and OPEB costs to the December 2008 level, which is known and measurable. The AIU initially proposed to set Pension and OPEB expense at the budgeted 2010 level; however, in surrebuttal testimony, the AIU revised its proposal to set the test year expense to the level for the 12 months ending September 30, 2009.

Staff witness Ebrey removed the Pension and OPEB adjustment proposed by the AIU since the amounts proposed by the AIU are not known and measurable. The current 2010 pension budget is based on the updated actuarial report provided to the Companies in July 2009. The AIU proposed updates to its initial position (which was based on a January 2009 actuarial report) in Supplemental Direct Testimony filed in July 2009. The fact that the budgeted amounts changed in the six months from January to July confirms Staff's position that the amounts do not meet the Commission's known and measurable standard. The 2010 benefits budget is based on a variety of assumptions, expectations and trend analyses, none of which meet the Commission's known and measurable criteria. (Staff Ex. 15.0, p. 18)

The actual amounts recorded in the Companies' books for pension expense at September 30, 2009 are not known and measurable because those estimated amounts are based on the reports prepared by Towers Perrin at January 2009 and July 2009. The actual Pension Cost for the year ending December 31, 2009 and the Employer Contribution for the Plan Year beginning January 1, 2009 will not be determined until the year end 2009 actuarial study has been completed, after the record in these proceedings will be marked heard and taken.[18] In addition, the changes to AIU headcount as a result of the Workforce reduction occurring in the 4th quarter of 2009 are not reflected in the amounts recorded on the AIU books as of September 30, 2009. (Tr., pp. 787-788, December 17, 2009) Thus, the Companies' alternate proposal to include pension costs through September 2009 does not reflect a known and measurable change and must be rejected. (*Id.*, p. 19)

During the evidentiary hearings, the AIU attempted to gain Staff's agreement that the record in these proceedings could be held open until the final actuarial study for 2009 was prepared. Staff is unaware of any other proceeding where the record is purposely held open for the entry of documentation supporting a pro forma adjustment until well after the hearings on the matter have concluded. (Tr., pp. 758-760, December 17, 2009) Such a tactic is clearly contrary to the known and measurable criteria which

[18] The Actuarial valuation report for 2008 was dated February 2009 as provided pursuant to Section 285.305(g).

83 Ill. Adm. Code 287.40 requires to be "individually identified and supported in the direct testimony of the utility" when the case is filed, not after the evidentiary hearing.

Both Staff and the AIU reflected reductions related to the Production Retiree expense that is included in the Pension and OPEB balances. The theory behind the two proposals is the same. The AIU and Staff agree that the costs associated with Production Retiree pensions and OPEBs should be removed from the revenue requirement. The only difference is the timeframe for the costs that are removed. (Staff Ex. 15.0, p. 21) Thus, the decision on this issue is derivative of the Commission conclusion on the proper period for measurement of pension and OPEB costs.

4. NESC Expenses

Staff witness Rockrohr expressed concern that AIU proposed to recover a greater amount than he believed appropriate for its correction of National Electrical Safety Code ("NESC") violations. In his direct testimony, Mr. Rockrohr explained that AIU is required to repair or replace distribution facilities that are in violation of the NESC, and explained that the AIU's Circuit Inspection Program appears to be an effective tool for AIU to use in order to identify locations that require NESC-related repairs. (Staff Ex. 11.0R, pp. 12-13) Mr. Rockrohr also explained that the Commission's Final Order in AIU's prior rate case stated in relevant part, "...ratepayers will not be responsible for paying the costs associated with correcting distribution facilities that were initially constructed in a manner that does not comply with the NESC." (Order, Docket Nos. 07-0585 – 0590 (Cons.), September 24, 2008, p. 142)

Staff witness Rockrohr asserted that ratepayers should not bear AIU's estimated test year repair costs for four specific NESC-related repair categories for which AIU proposed recovery: (1) missing guy guards; (2) down guys where no insulator exists in the guy wire; (3) overhead guys where no insulator exists in the guy wire; and (4) ungrounded metal underground risers. Mr. Rockrohr pointed out that for all four of these repair categories the utility left off a required part when making the initial installation, so that the installation was in violation of the NESC. Though the cost of installing the part would have been negligible at the time of the initial installation, AIU proposes to recover from ratepayers its estimated test year costs for installing the missing parts. AIU's proposal is inconsistent with the Commission's Order in Docket Nos. 07-0585 - 0590 (Cons.), and would cause the utilities to recover amounts far greater than what the utility's costs would have been, had the utility installed the part at the time of initial construction, as it should have done. (Staff Ex. 24.0R, pp. 8-10)

In support of AIU's proposal to recover its estimated test year costs for the four specific NESC-related repairs that Staff witness Rockrohr identified, Ameren witness Justice explained that AIU determined it did not re-do work previously performed by the utility when making the repair, so AIU did not categorize those repairs as "re-work" to be excluded from cost recovery. Mr. Justice used the example of guy guards to illustrate AIU's method of categorizing work as either "re-work" or "new work," explaining that if a guy wire does not have the required guy guard, then ratepayers would not have paid for the guy guard in the first place, so that installing the guy guard would be "new work," and should be eligible for cost recovery. Mr. Justice concluded that no locations with missing guy guards should be considered NESC-related re-work, and ratepayers should bear all test year costs related to installing them. Likewise, AIU reasoned that ratepayers had not previously paid for missing down guy insulators, missing overhead guy insulators, and missing grounds on metal underground risers, and therefore should pay AIU's estimated test year installation costs for each of these items. (Ameren Ex. 11.0E (Revised), pp. 6-11)

AIU did not know its actual test year costs for its NESC-related repair work, so it estimated its test year costs for each NESC-related repair activity by averaging the costs of jobs with work descriptions that appeared to closely match each NESC-related repair category. (Ameren Ex. 11.0E (Revised), pp. 11-12) In direct testimony, Mr. Justice estimated that the amount of its expenditures for NESC-related repairs that should be eligible for recovery is $4,500,000, and the amount of its expenditures for NESC-related repairs that should be excluded from recovery is $8,600,000. (Ameren Ex. 11.0E (Revised), pp. 5-6)

Mr. Justice further explained: "Installing a missing guy guard, insulator, or ground merely completes the construction of the infrastructure in compliance with the NECS" (Ameren Ex. 66.0, p.3) and Mr. Justice claimed that ratepayers never paid for the installation costs of the missing parts. Mr. Justice used an example of installing smoke detectors in two homes, one with smoke detectors installed incorrectly, and one with no smoke detectors installed at all, in order to illustrate AIU's position on cost recovery for NESC-related repairs. He stated that in one home there is time and cost required to correct the improperly installed smoke detectors, and in the other there was never an initial amount of time and cost spent installing the detectors. (Ameren Ex. 66.0, p. 4)

Mr. Rockrohr did not find AIU's rationalization for charging ratepayers the utility's estimated test year cost to install missing parts to be reasonable, and opined that the requirements for the missing parts have existed for several decades in Illinois, so that the utility should have known of the requirement at the time of initial construction, and initially completed the installation correctly. (Staff Ex. 11.0R, p. 16) Mr. Justice agreed with Mr. Rockrohr that the missing parts should have been installed at the time of initial construction. (Ameren Ex. 35.0, pp. 4-5) As mentioned, in his surrebuttal testimony, Mr. Justice's used an analogy of smoke detectors installed in homes to explain why AIU did not propose to charge customers for re-installing parts that were installed improperly, but proposed to recover costs for installing parts that were not installed at all. (Ameren Ex. 66.0, p. 4) However, Mr. Justice's analogy does not accurately describe the situation associated with AIU's NESC-related repairs. For the four NESC-related repairs that Mr. Rockrohr identified, the situation is not that AIU did not install down guys, overhead guys, or metal underground risers; the situation is that AIU left required parts off of these facilities when it installed them – more similar to installing a smoke detector but leaving the sensor or battery out of it. Mr. Rockrohr pointed out that repair costs associated with individual locations for each of the four NESC-related repair activities identified are not large, but the large number of locations where AIU performed each repair activity during the test year causes the aggregate costs to warrant the Commission's careful consideration. In every case, the cost for the utility to install the missing part when the facility was initially constructed and that the NESC required would have been negligible, but AIU's test year costs are not negligible. For example, AIU indicated it seeks to charge ratepayers $235.52 per repair location to install insulators in down guys at more than 5200 locations, even though AIU's average material cost for the insulators has been approximately $16, and its incremental labor cost to install the insulator would have been negligible at the time of initial construction. (Staff Ex. 11.0R, pp. 15-17) As another example, AIU proposes to charge ratepayers $125 per installation for installing 6399 guy guards during the test year, even though each guy guard costs slightly more than $2, and would have added no additional labor costs to the initial installation. (Staff Ex. 11.0R, pp. 19-20; Ameren Ex. 66.0, p. 6)

In his surrebuttal testimony, Mr. Justice suggested that even if the Commission were to accept Mr. Rockrohr's position regarding NESC-related repairs, his proposed disallowance for guy guards should be modified. Mr. Justice indicated that AIU believes 90% of the 6399 missing guy guards that AIU installed during the test year had been removed after the AIU installed them. (Ameren Ex. 66.0, p. 5) Staff's opinion has not changed with regard to guy guards. Mr. Rockrohr believes, based upon his experience working for two different electric utilities, that the percentage of guy guards removed after they are initially installed is very small, and provided his opinion that certainly no more than 10% of the 6,399 guy guards that AIU installed during the test year were replacements for guy guards that had been previously installed and removed. (Staff Ex. 11.0R, pp. 19-20)

Mr. Justice further recommended that, should the Commission choose to allow AIU to recover only material costs for the guy guards, insulators, and grounds, then test year costs should be used, rather than average material costs. (Ameren Ex. 66.0, p. 6) Mr. Rockrohr pointed out, however, that AIU could not demonstrate whether or not ratepayers have already paid for the missing parts at locations with NESC violations, and so he does not recommend that the Commission allow cost recovery for these materials. (Staff Ex. 24.0R, pp. 10-11) However, should the Commission choose to allow recovery of the utility's material costs associated with these NESC-related repairs, Staff's position is that use of the average material cost listed in Staff Ex. 24.0R Attachment E, would more accurately reflect the material costs at the time that the material should have been installed. Therefore, should the Commission decide to allow material cost recovery for the four NESC-related repairs Mr. Rockrohr identified as re-work, which Staff does not recommend, then the recovery that the Commission allows should be the normalized costs shown in Staff Ex. 24.0R Attachment E, rather than the test year material costs suggested by AIU.

Finally, with regard to AIU's obligation to correct NESC violations that it discovers, Staff wishes to make the Commission aware of AIU's lengthening timelines. In its NESC Corrective Action Plan, dated October 31, 2007, AIU had agreed to identify and correct all existing NESC violations on the three electric utilities' distribution circuits by the end of 2011. After it made its rate case filing in June of 2009, AIU notified Staff in July that it was extending the time to correct its existing NESC violations until the end of 2013. (Staff Ex. 11.0R, p. 13) Then, in his surrebuttal testimony, Ameren witness Justice indicated that AIU might extend its NESC violation correction timelines still further. (Ameren Ex. 66.0, pp. 9-10) Staff agreed with Cities' witness Steven Brodsky that AIU should correct its NESC violations as quickly as it can by using a systematic and thorough inspection process. (Staff Ex. 24.0R, p. 18) Staff is very concerned that after already extending its previously agreed upon timelines in July of 2009, in its surrebuttal testimony, AIU threatened to delay completion of its corrections of NESC violations still further if the Commission does not grant the recovery it seeks. Staff finds this veiled extortion by the AIU to be troubling. The utilities are already in violation of NESC and Commission rules as a result of their own construction practices at the time of initial construction (Staff Ex. 11.0R, p. 12), and AIU admitted that it should have known the missing parts were required at the time of initial construction (*Id.*). Staff encourages the Commission to order AIU to complete its corrective actions for existing

NESC violations by no later than the end of 2013, as AIU has stated it currently is planning to do.

5. Amortization of IP Merger Expense/Regulatory Asset

The Commission should accept Staff's adjustment to the amortization of the AmerenIP Regulatory Asset which limits the recovery to the amount allowed by the Commission in Docket No. 04-0294. (Staff Ex. 2.0, pp. 12-13) Ameren witness Stafford argued that Staff's adjustment was flawed for the following reasons:

1) Extends the time frame allowed for pro forma adjustments beyond that established by 83 Ill. Adm. Code 287.40;
2) Does not include any other changes to occur after May 2010 through January 2011 which would offset the amortization amount;
3) Does not consider the length of new rates approved in this proceeding;
4) Constitutes single issue ratemaking, although he largely discusses that claim in the context of AG/CUB and IIEC; and
5) AmerenIP has not fully recovered its regulatory asset as of December 31, 2010.

Staff rebutted each of these arguments in turn after first pointing out how Mr. Stafford deflects the attention from the central issue by misapplying certain ratemaking principles. The central issue here is the appropriate amount of the regulatory asset amortization to be reflected in rates to comply with the finding and ordering paragraphs of the Order in Docket No. 04-0294. Specifically, AmerenIP should reflect the appropriate level of expense to include in AmerenIP's rates that will recover no more than the Order in Docket No. 04-0294 allowed during the specific time period. (Staff Ex. 16.0, pp. 7-11) The evidence fully supports Staff's adjustment which spreads the remaining 8-months amount[19] to be recovered over the two year amortization period consistent with the proposed period for rate case expense.

6. Economic Development Expenses

The Commission should adopt Staff's adjustments to remove Economic Development ("ED") labor and labor-related costs from each Company's respective revenue requirement, as presented in Staff Ex. 18.0R, Schedule 18.06. Based on the guidance of 220 ILCS 5/9-225, which prohibits recovery of costs of a promotional, institutional, or goodwill nature, the ED labor and labor-related costs included by the AIU are not recoverable in rates.

In direct testimony, Staff witness Bridal proposed an adjustment to remove Demonstrating and Selling Expenses, account 912, from each gas utility's respective revenue requirement because the transactions identified in that account were not recoverable. (Staff Ex. 4.0, pp. 28-29) A similar adjustment to the AIU electric utilities was not necessary, as those Companies did not claim any account 912 costs. In rebuttal testimony, AIU offered alternative adjustments which purported to include in account 912 only what AIU term as "economic development labor and labor-related costs" for both the AIU electric and gas utilities. (Ameren Ex. 29.0 (Revised), p. 37)

In rebuttal testimony, Staff witness Bridal proposed an adjustment to remove the newly-defined ED expenses as presented in the AIU rebuttal testimony. Review of AIU rebuttal testimony and DR responses led Mr. Bridal to conclude "economic development labor and labor-related costs" as presented by AIU, are for promotional, institutional, and goodwill purposes, which, while perhaps promoting good corporate citizenship,

[19] On cross examination, Staff witness Ebrey agreed that the calculation provided on Schedules 16.02 IP-E and 16.02 IP-G should reflect 8 months on line 3 rather than the 6 months on the schedules filed on e-docket. (Tr., p. 799, December 17, 2009) This correction is reflected on Appendices E and F filed with this Initial Brief.

keeping the Companies in contact with other members of the business community, and recruiting new corporate customers, are not necessary in providing utility service. Such costs should be the responsibility of the investors, not the ratepayers. (Staff Ex. 18.0R, p. 16) In surrebuttal testimony, AIU expressed its disagreement with Staff, further explaining the services provided by the ED Department, a part of AMS. (Ameren Ex. 70.0)

There appears to be no disagreement regarding the nature of the services provided to the AIU by the AMS ED Department. AIU themselves describe the services as being to "attract new business growth and investment." (Ameren Ex. 70.0, p. 3) Further, AIU state the services "successfully prepare communities to compete for new business investment and business retention," and "support canvassing of existing business for retention and expansion opportunities." (*Id.*, p. 4) The disagreement relates to who should shoulder the burden of the expenses related to these services. Staff maintains that the AIU shareholders should bear this burden, as the costs are non-recoverable per Section 9-225 of the Act, and benefit the Company and shareholders by increasing Company revenues.

In effort to justify the recoverability of ED costs, AIU stated in their surrebuttal testimony that the services benefit ratepayers by providing information to prospective new businesses, by attracting new investment to areas that have existing AIU infrastructure, by spreading fixed operating costs across a broader customer base, and by ensuring continued use of existing infrastructure. (*Id.*, pp. 4-5) However, under cross-examination, AIU witness Kearney admitted, regarding the ED services, that "obviously the shareholders benefit as well." (Tr., p. 80, December 14, 2009) AIU also aver that the services provided by the ED Department are an integral component in the process of providing utility service. (Ameren Ex. 70.0, p. 7) Again, upon cross-examination, when asked if the AIU would still be able to provide utility service in the absence of ED cost recovery, AIU witness Kearney readily admitted, “Yes, we’d certainly provide utility service in the absence of such programs.” (Tr., pp. 80-81, December 14, 2009) These revelations confirm Staff’s conclusion that ED costs are not necessary in providing utility service, and such costs should be the responsibility of the investors, not the ratepayers. (Staff Ex. 18.0R, p. 16)

Considering the guidance of Section 9-225 of the Act and the record in this docket, the Commission should adopt Staff’s adjustment to remove ED costs from each Company’s revenue requirement.

7. Workforce Reduction

The Commission should accept Staff’s revised proposed adjustment for the AIU workforce reduction in the attached Appendices which:

1. Corrects payroll tax costs consistent with payroll taxes associated with other pay related adjustments, and
2. Does not reflect an offset for the one-time costs associated with severance pay to those employees taking the voluntary separation package.

In surrebuttal testimony, the AIU discussed certain disputes it has with Staff’s rebuttal adjustments. (Ameren Ex. 51.0 (2nd Revised), pp. 12-14) Accordingly, Staff has revised its rebuttal position adjustment so that the incentive compensation costs already removed from the operating expenses are not double counted[20]. In addition, Staff has also reflected the jurisdictional allocations included in Ameren Exhibit 51.9, for its electric utilities in the revised adjustment schedules.

[20] Ameren Ex. 51.9, Schedule 9 calculates the percentage of incentive compensation included in its revenue requirements. Staff has likewise performed the same calculation based on the percentage of original incentive compensation included in Staff’s revenue requirements for each AIU.

The AIU calculated the amounts for payroll taxes associated with the workforce reduction based on factors calculated by dividing payroll taxes into labor. As is clear from the AIU response to Staff DR TEE 20.08 (Staff Group Cross Ex. 1-DD), the resulting factors range from 4.19% - 5.25% for total payroll taxes, all clearly less than the amounts for FICA tax alone. During cross examination, AIU witness Stafford agreed that the tax rates for each of the AIU would include 7.65% for FICA tax, 0.8% for FUTA tax, 0.6% for SUTA tax, and further that these tax rates would not vary between the utilities. Mr. Stafford further acknowledged that the complicated calculation he uses for the payroll taxes associated with the workforce reduction does not in fact accurately reflect the correct adjustment and would require correction should the Commission approve the AIU proposed adjustment. (Tr., pp. 296-301, December 15, 2009)[21]

Staff's adjustment for payroll taxes reflects the same calculation used for other payroll tax related adjustments, multiplying the amount of the compensation-related adjustment by 7.65%.

While the AIU argue that the costs for severance pay should be recovered over a three year period similar to rate case expense, they also agree with Staff that those costs are one-time costs. (Ameren Ex.49.0 (2nd Revised), p. 9)

8. Electric Distribution Tax/Public Utilities Revenue Act Tax

The Commission should accept Staff's adjustment to remove the AIU pro forma adjustment which weather-normalizes the Electric Distribution Tax expense. The AIU

[21] Mr. Stafford agreed that in the event the Commission approves the AIU proposed adjustment for the workforce reduction, the associated payroll tax adjustment would need to be revised. (Staff Group Cross Ex. 1-DD Tr., p. 300, December 15, 2009)

have not shown that the AIU's share of the statutory cap on the tax will increase during the period rates determined in these proceedings are in effect. (Staff Ex. 15.0, p. 23)

The amount of electric distribution tax for a given calendar year is a combination of the amount remitted quarterly by the utility based on a tiered structure of rates for delivery volumes as well as credit memoranda resulting from the statutory cap on the tax, as discussed by IIEC witness Stephens.[22] The Companies' response to Staff DR TEE 4.03 Attach indicates that the AIU have received credit memos in each year for which information was provided. (Staff Ex. 15.0, pp. 22-23) The AIU adjustment was simply based on the application of the tiered formula for computing the tax without considering the credit memos that are routinely received by the Companies.

In surrebuttal, AIU witness Stafford revised his adjustment to reflect the test year level of refunds (credit memoranda) as a reduction to his weather-normalized tax amount. (Ameren Ex. 51.0 (2nd Revised), p. 24 and Ameren Ex. 51.13) While Staff does agree this is an improvement over the initial proposal which did not reflect the refunds, it still results in an overall increase over the 2008 net costs, which Ameren has not demonstrated will occur.

9. Transportation Fuel Expense

Staff disputes AIU's gasoline and diesel fuel pricing utilized in the calculation of transportation fuel expenses in the test year for each of the Ameren gas and electric utility companies. Specifically, Staff notes that the average gasoline and diesel fuel pricing used by AIU includes excessive prices from mid-2008 that are not representative of the current transportation fuel expenses. As a result, Staff determined the AIU's proposal did not result in just and reasonable rates.

[22] IIEC Ex. 1.0, p. 17.

Staff noted that AIU's transportation fuel expense must meet the requirements of Section 9-101 of the PUA. The Act does not allow a utility to pass costs onto ratepayers unless those costs are just and reasonable. Section 9-101 states as follows:

> All rates or other charges made, demanded or received by any product or commodity furnished or to be furnished or for any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge made, demanded or received for such product or commodity or service is hereby prohibited and declared unlawful. All rules and regulations made by a public utility affecting or pertaining to its charges to the public shall be just and reasonable.

Further, Section 9-201(c) provides:

> If the Commission enters upon a hearing concerning the propriety of any proposed rate or other charge, classification, contract, practice, rule or regulation, the Commission shall establish the rates or other charges, classifications, contracts, practices, rules or regulations proposed, in whole or in part, or others in lieu thereof, which it shall find to be just and reasonable. In such hearing, the burden of proof to establish the justness and reasonableness of the proposed rates or other charges, classifications, contracts, practices, rules or regulations, in whole and in part, shall be upon the utility. No rate or other charge, classification, contract, practice, rule or regulation shall be found just and reasonable unless it is consistent with Sections of this Article.

Staff's review determined that AIU's proposed transportation fuel expenses were not just and reasonable. Instead, Staff recommends each AIU utility revalue its transportation fuel expenses using an average gasoline price of $2.51/gallon and an average diesel fuel price of $2.78/gallon.

In response to Staff's concerns, AIU revised its initial position of using 2008 gasoline and diesel fuel costs to value its transportation fuel expense amounts and instead proposed to use a three-year average for the calculation of transportation fuel costs, namely, the period August 2006 through July 2009, to price gasoline and diesel fuel instead of the pricing that Staff recommended. (Ameren Ex. 34.0, pp. 20-22)

Staff disputed AIU's proposal because it continues to place reliance on the mid-2008 gasoline and diesel fuel prices and as a result causes an overstatement of the costs going forward. Staff reached this conclusion after demonstrating that fuel prices have not remained at their 2008 level, but have declined and AIU's three year average prices still exceed the current gasoline and diesel prices. In short, Staff did not find AIU's proposal resulted in just and reasonable rates. (Staff Ex. 13.0, pp. 19-20)

Specifically, Staff noted that the average transportation fuel prices proposed by AIU include prices that are excessive and unnecessarily skew the average above current prices. AIU's proposal relies on gasoline and diesel fuel prices from 2008 that were some of the highest recorded prices experienced by AIU. Staff demonstrated that the 2008 transportation fuel prices are outliers and, as such, recommends that the Commission not rely on those fuel prices to value the transportation fuel expense because that would result in rates that are not just and reasonable. (Staff Ex. 27.0R, pp. 16-17)

In support of its conclusion, Staff provided a review of the EIA/Short Term Energy Outlook, U.S. Nominal prices[23] that indicates gasoline and diesel fuel prices experienced in 2008 are not representative of gasoline and diesel prices on a going forward basis. Table 1, below, shows the EIA estimated gasoline prices for January 2010 to December 2010 in comparison to AIU's actual 2008 prices.

Table 1

Month	Cents/Gallon 2010 EIA/STEO	Cents/Gallon 2008 Ameren	Difference (Cents)
January	256	309	53

[23] The Energy Information Administration ("EIA") is an unbiased source of current prices for both gasoline and diesel fuel. (Staff Ex. 13.0, p. 22)

February 2010	257	308	51
March	261	329	68
April	269	351	82
May	275	382	107
June	276	**411**	135
July	274	**411**	137
August	278	383	105
September	277	376	99
October	274	311	37
November	269	221	-48
December	270	174	-96
Average	270	331	61

(Staff Ex. 27.0R, pp. 17-18) (**emphasis added**)

Table 1 indicates that the EIA price forecast in 2010 for gasoline prices shows no trend of returning to the high gas costs Ameren experienced in 2008, especially those gasoline prices in the $4/gallon range which AIU utilized in its calculation of the average gasoline prices. (*Id.* pp. 17-18) Further, Table 1 shows, on average, a $.61/gallon variance between the currently forecasted 2010 gasoline prices and those Ameren experienced in 2008.

Table 2, below, provides the same information as Table 1, but for diesel fuel instead of gasoline. Also, as noted above for Table 1, Table 2 indicates that the EIA price forecast for diesel fuel in 2010 shows no trend of returning to the diesel prices reached in 2008, especially those diesel prices in the $4/gallon range which AIU utilized in its calculation of the average diesel fuel prices. (*Id.*, pp. 18-19) Further, Table 2 shows, on average, a $1.03/gallon variance between the currently forecasted 2010 diesel prices and those AIU experienced in 2008.

Table 2

Month	Cents/Gallon 2010 EIA/STEO	Cents/Gallon 2008 Ameren	Difference (Cents)
January	264	331	67
February	265	338	73
March	269	388	119
April	274	**408**	134
May	276	**443**	167
June	278	**468**	190
July	277	**470**	193
August	280	**430**	150
September	285	**402**	117
October	289	358	69
November	289	288	-1
December	290	245	-45
Average	278	381	103

(Staff Ex. 27.0R, pp. 17-18) (**emphasis added**)

Staff's review of the information in Tables 1 and 2, indicates, that the prices experienced in 2008 by AIU for gasoline and diesel fuel are not within the expected range of fuel prices the Company will experience after rates granted by the Commission in the current proceeding go into effect. Given the overwhelming demonstration that 2008 gasoline and diesel fuel prices are excessive, Staff cannot support the inclusion of the 2008 fuel costs in the average that AIU proposes. (*Id.,* p. 19)

AIU identifies three concerns regarding the gasoline and diesel fuel prices utilized in Staff's calculation of average fuel prices. First, AIU noted that Staff's analysis arbitrarily chose fuel prices from August 2008 to July 2009. Second, AIU claimed that fuel prices are volatile and fluctuating, and as a result, AIU recommended normalizing the average fuel price over a three-year period, August 2006 to July 2009, versus Staff's one-year proposal. (Ameren Ex. 61.0 (Revised), pp. 2-3) Finally, AIU asserts that the EIA/Short-term price forecasts are subject to frequent revisions. (*Id.,* pp. 5-6)

Regarding AIU's first claim, Staff's analysis did not choose the fuel prices arbitrarily. In fact, Staff's selection was the most recent EIA data available at the time Staff filed its direct testimony. (Staff Ex. 27.0R, pp. 16-17) Therefore, AIU's claim that Staff's analysis arbitrarily applied fuel prices from August 2008 through July 2009 is unsubstantiated. Further, Staff asserts its recommendation yields a more accurate representation of fuel prices AIU will experience when rates granted by the Commission go into effect. (*Id*., p. 19)

Regarding AIU's second claim that transportation fuel prices are volatile and fluctuate, Staff does not dispute this obvious statement. However, AIU went further and indicated the best method to normalize those prices is to utilize a three-year average. Staff disagrees with that assertion. Staff's analysis showed AIU's pricing average placed reliance on 2008 transportation fuel prices that are the highest gasoline and diesel fuel prices experienced by the Companies. (Staff Ex. 13.0, p. 21; Staff Ex. 27.0R, pp. 16-17) Staff then noted that the inclusion of these costs would result in an overstatement of costs attributed to transportation fuels for AIU on a going forward basis. (Staff Ex. 13.0, pp. 19-20)

Staff admits it is possible for significant increases or decreases to occur in the price of transportation fuels and that no one can successfully predict the future. However, Staff's analyses and review demonstrates that AIU's proposal placed reliance on 2008 transportation fuel prices that are outliers and that Staff's proposal is consistent with the current projection of transportation fuel costs that AIU will experience when its rates go into effect. (Staff Ex. 27.0R, pp. 17-19) Further, Staff notes its reliance on one year of EIA data is consistent with a previous case, namely the Peoples Gas and North Shore Gas rate case in Docket Nos. 09-0166/09-0167 (Cons.). (Staff Ex. 13.0, p. 22)

Regarding AIU's final claim that EIA updates its forecasts frequently, again, Staff does not dispute this statement; in fact, Staff would note that EIA provides monthly updates. However, this fact does not support the use of AIU's proposal over Staff's recommendation. A forecast of future events will have inaccuracies. Therefore, AIU's discussion that shows significant differences have occurred between actual and forecasted EIA information, while accurate, ignore the basic fact. The current and best information available regarding future transportation fuel costs support Staff's recommendation and no one knows if major events, such as a hurricane or any other highly speculative event, could influence those prices in the near future. In other words, AIU's selective comparison points out some of the highest differences between EIA/Short-term forecasted and actual fuel prices, but does not change what the current forecast shows.

Staff concluded that AIU's proposal places reliance on 2008 transportation fuel costs, especially the mid-2008 fuel prices whose gas costs are outliers and would result in AIU receiving a transportation fuel expense allowance that was excessive and would not result in just and reasonable rates. Further, Staff's proposal is in line with the independent

EIA transportation fuel projections for 2010, meaning that Staff's proposal is consistent with costs AIU would experience for transportation fuel expenses once its rates go into effect. Therefore, Staff continues to recommend a downward adjustment of AIU's Operation and Maintenance (O&M) costs associated with its transportation fuel. (Staff Ex. 13.0, pp. 19-20)

The use of Staff's proposal would result in the reduction in operation and maintenance expense for each AIU utility as follows: AmerenCILCO, $27,000 (gas) and $180,000 (electric), AmerenCIPS, $51,000 (gas) and $494,000 (electric), and for AmerenIP $72,000 (gas) and $560,000 (electric).

10. Account 887 Expense –Maintenance of Mains

Staff found that AmerenIP's requested expense for its Account 887, "Maintenance of Mains," was higher in the test year than in any other period reviewed for this account. Further, AmerenIP was unable to explain why Account 887 had experienced such a large increase from historical periods. As a result, Staff recommended that the Commission average AmerenIP's Account 887 expense amount over the three year period, 2006-2008. (Staff Ex. 13.0, pp. 18-19) In response to Staff's recommendation, AmerenIP proposed to use the most recent three-year period of actual experiences to value this account. Staff disputes this proposal due to AmerenIP's inability to demonstrate the just and reasonableness of its requested value.

AmerenIP was unable to explain why the costs associated with Account 887 have dramatically increased over the past three years. Specifically, Staff noted that a comparison of AmerenIP's 2008 test year expense for Account 887 to other years and found that 2008 expense was the highest value, by far, as shown in Table 1 below.

Table 1

Distribution Expenses-Maintenance					
Account 887	2006	Increase 06-07	2007	Increase 07-08	2008
	$1,388,100	$1,588,533	$2,976,633	$2,004,360	$4,980,993

The comparison in Table 1, above, shows that AmerenIP's Account 887 expense amounts more than doubled between 2006 and 2007 and then increased significantly between 2007 and 2008, such that the comparison between 2006 and 2008 [(4,980,993-1,388,100) /1,388,1000 = 2.59] shows a 259% increase in expenses over a three year period.

However, AmerenIP could not explain why such a large increase occurred. AmerenIP did provide a list that designated each cost that contributes to the large increase from 2007 to 2008; however, AmerenIP could not provide any meaningful explanation regarding the increase. (Staff Exhibit 13.0, p. 17) AmerenIP did indicate that the increase in costs associated with this account was due to increases in labor and labor related loading. AmerenIP also indicated that it is unable to track costs passed through Account 887 due to "so many activities and variables," and "operational reasons." (Staff Ex. 27.0R, p. 13) Finally, Staff noted that AmerenIP, in response to a Staff DR, indicated that it could not provide any further information regarding Account 887 to support the drastic increase in its requested expense. (*Id.*, pp. 12-13) This is unacceptable. AmerenIP must demonstrate that the costs it requests to pass onto ratepayers are just and reasonable. AmerenIP claimed it was unable to track the costs associated with this account down to a precise dollar amount from 2006-2008. AmerenIP was unable to explain why the large increase occurred. AmerenIP could not point to any specific projects or provide any other meaningful detail regarding this account. (*Id.*) In short, AmerenIP wanted Staff to take it on faith that these large increases resulted in just and reasonable expenses that it should pass onto ratepayers. Staff disagrees.

Staff also noted it limited its comparison to the last three full calendar years because AmerenIP was transitioning to Ameren's accounting system in 2005. Therefore, expense data for AmerenIP prior to 2006 uses a different accounting system and will not necessarily correlate to the Ameren accounting system. However, Staff did note that the Account 887 expense from the period prior to 2006 was approximately the same or less than the 2006 amount. (Staff Ex. 13.0, p. 18)

Rather than adequately addressing Staff's concern regarding why its expenses have increased so dramatically, AmerenIP proposed to normalize the costs associated with this account using the three-year normalization period ending September 2009. (Ameren Ex. 30.0, p. 5)

Staff disputes AmerenIP's proposal because it has still failed to address why its expenses associated with Account 887 increased so dramatically between 2006 and 2008. Further, AmerenIP failed to provide any supporting data that demonstrated that the dramatic cost increases to Account 887 were just and reasonable. (Staff Ex. 27.0R, p. 12) Without this information, Staff cannot verify the just and reasonableness of AmerenIP's requested expense amount for Account 887.

Staff established that the expense for Account 887 was higher in the test year than any other period reviewed for this account. Staff also demonstrated that AmerenIP is unable to provide sufficient information to allow Staff to conclude its requested expense amount is a just and reasonable request. Therefore, Staff continues to recommend that the Commission average AmerenIP's Account 887 expense amount over the three years of available data, 2006-2008. The Commission's acceptance of Staff's recommendation will result in a $665,000 reduction to AmerenIP's requested Account 887 expense amount.

11. Injuries and Damages Expense

The Commission should accept Staff's adjustment to the AIU test year Injuries and Damages Expense for AmerenIP to remove the effects of HMAC costs from the normalized level. (Staff Ex. 1.0, p. 29) The AIU accepted Staff's adjustment. (Ameren Exhibit 29.0 (Revised), p. 6)

IIEC witness Meyer agreed with normalizing the level of Injuries and Damages expense, but took issue with adjusting each year's costs for inflation using the CPI index, arguing that the fluctuations in the cost level from year to year was a function of the number of claims and the size of the claims processed in any given year. (IIEC Ex. 3.0, p. 8) The AIU counter that argument by claiming that the inflation factor is not meant to level out the fluctuations in cost, but rather to reflect the increases in costs from year to year for materials and labor associated with those claims. (Ameren Ex. 30.0, p. 3) Staff did not take issue with the use of the CPI Index in the AIU's calculations.

12. Overall Reasonableness of O&M Expenses

The overall reasonableness of the O&M expenses of the electric Ameren Illinois Utilities was called into question by AG/CUB, based on an evaluation of the AIU's performance in this cost area using econometric benchmarking techniques. (AG/CUB Ex. 1.2, Executive Summary) Staff took no position and presented no testimony regarding the results of the evaluation.

13. Other

D. Recommended Operating Income/Revenue Requirement

Based on the operating expense statements for the electric and gas utilities originally proposed by CILCO, CIPS and IP and Staff's proposed adjustments to operating revenues and expenses as summarized above, the total electric utility delivery services net operating income proposed by Staff for CILCO is $25,540,000, for CIPS is $42,785,000, and for IP is $132,300,00. The total gas utility net operating income proposed by Staff for CILCO is $15,262,000, for CIPS is $15,028,000, and for IP is $44,640,000. The operating expense statements may be summarized as follows:

1. Electric

Staff Recommended Operating Income/Revenue Requirements
(In Thousands)

Description	CILCO	CIPS	IP
Operating Revenues	$121,954	$241,696	$474,397
Other Revenues	5,043	14,628	18,493
Total Operating Revenues	$126,997	$256,324	$492,890
Uncollectible Accounts	1,027	2,352	5,108
Distribution Expenses	30,133	65,666	102,574
Customer Accts Expense	8,939	15,534	23,837
Admin & General Expense	24,153	41,329	78,556
Depreciation & Amort. Expense	21,097	52,629	78,382
Taxes Other Than Income	6,590	17,816	27,392
Total Operating Expense	$91,938	$195,326	$315,849
State Income Tax	1,747	3,350	8,215
Federal Income Tax	7,772	14,863	36,526
Total Operating Expense	$101,457	$213,539	$360,590
Electric Net Operating Income	$25,540	$42,785	$132,300

2. Gas

Description	**CILCO**	**CIPS**	**IP**
Operating Revenues	$67,055	$70,624	$160,443
Other Revenues	2,177	2,758	5,161
Total Operating Revenues	$69,232	$73,382	$165,604
Uncollectible Accounts	928	921	2,784
Production Expenses	928	1,093	1,121
Storage, Term, and Proc Expenses	1,666	1,867	3,596
Transmission Expenses	761	725	2,926
Distribution Expenses	17,235	18,221	31,160
Customer Accts Expense	6,735	5,485	11,641
Admin & General Expense	9,928	12,424	25,688
Depreciation & Amort. Expense	7,526	8,337	21,620
Taxes Other Than Income	2,757	3,054	5,930
Total Operating Expense	$48,464	$52,127	$106,465
State Income Tax	1,010	1,144	2,666
Federal Income Tax	4,496	5,083	11,833
Total Operating Expense	$53,970	$58,354	$120,964
Gas Net Operating Income	$15,262	$15,028	$44,640

IV. COST OF CAPITAL/RATE OF RETURN

A. Overview

Staff witness Rochelle Phipps presented the overall cost of capital and recommended a fair rate of return on rate base for CILCO, CIPS and IP,[24] which incorporates the cost of common equity Staff witness Janis Freetly recommended. (Staff Exs. 5.0R and 19.0R)

[24] Collectively, CILCO, CIPS and IP are the "Companies" or the "AIU." CILCO, CIPS and IP are each, individually, the "Company."

The table below summarizes Staff's recommended overall rates of return on rate for the AIU electric and gas delivery services:

Staff's Overall Rate of Return Recommendations

Company	Electric	Gas
CILCO	8.28%	7.95%
CIPS	8.06%	7.69%
IP	9.05%	8.70%

See Staff Ex. 19.0R, pp. 20-21.

B. Capital Structure

Ms. Phipps evaluated the Companies' capital structures by comparing the debt ratios from Staff's proposed capital structures to Moody's benchmark total debt to total capital ratio for low risk electric utilities. CILCO's and IP's 53% and 55% debt ratios, respectively, fall within the 50% - 75% debt ratio range for A-rated, low risk electric utilities; and CIPS' 46% debt ratio is within the debt ratio range for Aa-rated, low risk electric utilities (*i.e.*, below 50%). According to Moody's, an obligor rated 'A' is considered upper-medium grade and is subject to low credit risk and an obligor rated 'Aa' is considered high quality and is subject to very low business risk. This suggests that the AIU capital structures are commensurate with a strong but not excessive degree of financial strength. (Staff Ex. 5.0R, pp. 34-35) In Ms. Phipps' judgment, the capital structures she recommends reflect a reasonable balance of financial strength and cost. (Staff Ex. 5.0R, p. 5)

1. Central Illinois Light Company (CILCO)

a. Preferred Stock Balance – Immaterial Difference

Staff's calculation of CILCO's March 31, 2009 preferred stock balance equals $18,893,282. (Staff Ex. 19.0R, Schedule 19.01 CILCO) The AIU calculation equals $18,893,567. (Ameren Ex. 37.1, p. 1) The difference between those balances does not materially affect CILCO's overall cost of capital.

b. Short-Term Debt Balance - Resolved

Staff and the AIU agree that CILCO's March 31, 2009 short-term debt balance equals $32,017,993. (Staff Ex. 19.0R, Schedule 19.01 CILCO; Ameren Ex. 37.1, p. 1)

c. Long-Term Debt Balance – Immaterial Difference

Staff's calculation of CILCO's March 31, 2009 long-term debt balance equals $271,691,990. (Staff Ex. 19.0R, Schedule 19.01 CILCO) The AIU calculation equals $271,492,364. (Ameren Ex. 37.1, p. 1) The difference between those balances does not materially affect CILCO's overall cost of capital.

d. Common Stock Balance -Resolved

Staff and the AIU agree that CILCO's March 31, 2009 common equity balance equals $249,457,171. (Staff Ex. 19.0R, Schedule 19.01 CILCO; Ameren Ex. 37.1, p. 1)

2. Central Illinois Public Service (CIPS)

a. Preferred Stock Balance - Resolved

Staff and the AIU agree that CIPS' December 31, 2008 preferred stock balance equals $48,974,984. (Staff Ex. 19.0R, Schedule 19.01 CIPS; Ameren Ex. 37.1, p. 2)

b. Short-Term Debt Balance - Resolved

Staff and the AIU agree that CIPS' December 31, 2008 short-term debt balance equals $58,098,936. (Staff Ex. 19.0R, Schedule 19.01 CIPS; Ameren Ex. 37.1, p. 2)

c. Long-Term Debt Balance – Resolved

Staff and the AIU agree that, for the purpose of this case, CIPS' December 31, 2008 long-term debt balance equals $397,751,866. (Staff Ex. 19.0R, Schedule 19.01 CIPS; Ameren Ex. 37.1, p. 2)

d. Common Stock Balance – Resolved

Staff and the AIU agree that CIPS' December 31, 2008 common equity balance equals $478,676,606. (Staff Ex. 19.0R, Schedule 19.01 CIPS; Ameren Ex. 37.1, p. 2)

3. Illinois Power Company (IP)

a. Preferred Stock Balance – Resolved

Staff and the AIU agree that IP's March 31, 2009 preferred stock balance equals $45,786,945. (Staff Ex. 19.0R, Schedule 19.01 IP; Ameren Ex. 37.1, p. 3)

b. Short-Term Debt Balance – Resolved

Staff's calculation of IP's March 31, 2009 short-term debt balance equals $10,791,502. (Staff Ex. 19.0R, Schedule 19.01 IP) The AIU calculation equals $10,404,002. (Ameren Ex. 37.1, p. 3)

The AIU calculation improperly subtracts "excess cash" from short-term debt. (AmerenIP Ex. 13.0E (Revised), p. 7; AmerenIP Ex. 13.0G, p. 7) Ms. Phipps explained that the short-term debt calculation adopted by the Commission in IP's 2007 rate cases, which subtracted "excess cash" from short-term debt, was based on very specific, unique circumstances that do not apply in the instant case. Therefore, Ms. Phipps' short-term debt calculation does not subtract cash from short-term debt. Notwithstanding Staff's opposition to IP's improper short-term debt balance calculation, Ms. Phipps notes that IP's improper calculation does not materially affect IP's overall cost of capital. (Staff Ex. 5.0R, p. 24)

c. Long-Term Debt Balance – Contested

For ratemaking purposes, Ms. Phipps recommends IP's March 31, 2009 long-term debt balance equals $1,307,983,675. (Staff Ex. 19.0R, Schedule 19.01 IP) The AIU calculation equals $1,357,044,075. (Ameren Ex. 37.1, p. 3)

Ms. Phipps adjusted the principal amount of IP's 9.75% senior secured notes by calculating the amount of net proceeds that would be required to repay IP's $343.7 million borrowings under the 2006 and 2007 credit facilities. Ms. Phipps' calculation took into consideration IP's $1.2 million debt expense, 1.58% original issue discount, and 70 basis points underwriting fee. From this data, Ms. Phipps calculated that IP would have needed to issue $350 million in debt to raise sufficient cash to retire $343.7 million in short-term borrowings and therefore, she reduced the principal amount of IP's October 2008 debt issuance to $350 million from $400 million.[25] (Staff Ex. 5.0R, p. 30)

On October 23, 2008, IP issued $400 million, 9.75% senior secured notes, and used the proceeds to repay borrowings under the bank facilities and the money pool. IP asserts that it issued indebtedness totaling $400 million instead of a lower amount because this was the amount of IP's outstanding short-term debt at the time of the issuance. However, on October 22, IP was simultaneously contributing surplus funds to and borrowing from the money pool. Such transactions are unnecessary given the Commission's rules governing money pools require that money pool borrowers repay the principal amount of money pool loans on demand of the lending utility. Consequently, IP should have recalled its money pool loan and issued long-term debt in an amount sufficient to repay its credit facility borrowing rather than issue $400 million bonds given the high cost of long-term debt at that time. Thus, Ms. Phipps reduced the principal

[25] Staff Ex. 5.0R, p. 30, lines 541-556 provides a more detailed description of this adjustment.

amount of the 9.75% bonds from $400 million to $350 million. Absent this adjustment to IP's long-term debt schedule, IP customers would pay a 9.75% interest rate on $50 million bonds, the proceeds from which IP did not require for its electric and gas delivery services operations. (Staff Ex. 5.0R, pp. 25-26)

The AIU argue that IP did not recall its money pool loans in order to reduce the amount of the $400 million bond issuance because, "IP was holding cash and could temporarily provide CIPS with cash it needed." (Staff Ex. 5.0R, p. 26, citing AIU response to Staff DR RP 7.01) Essentially, AIU argues that on October 23, 2008, the date IP issued the 9.75% bonds, IP did not need the $X X million it was lending to CIPS. The AIU argument does not answer the question why IP did not recall the money pool loan. To the contrary, the AIU argument supports Staff's position that IP had liquidity available with which it could reduce its outstanding short-term debt before IP went to market securities in a high cost debt market. Appendix G presents IP's cash balances, money pool contributions and unused credit facility capacity from October 17, 2008, through March 31, 2009.

At the same time the AIU argue that IP did not need those funds it loaned to CIPS during October 2008, the AIU also argue:

> At the time of this debt financing, AmerenIP was fully utilizing its capacity under its two bank facilities and had to further meet its short-term borrowing requirements through borrowings from Ameren Corporation. (Ameren Ex. 28.0, p. 6)

Those two statements are contradictory. A utility that has cash available to lend should not simultaneously need to borrow additional short-term funds from either banks or affiliates. IP could have recalled its money pool loan to CIPS, in which case CIPS could have borrowed funds from Ameren Corporation ("Ameren") or from the credit facility.

Instead, IP borrowed $X million from Ameren on October 21, 2008, which IP repaid two days later. If IP had recalled its money pool loan, it would not have needed to borrow $X million from Ameren on October 21, 2008. If IP had not borrowed from Ameren on October 21, 2008, it could have reduced the size of its October 2008 long-term debt issue from $400 million to $350 million because it would have had less short-term debt to retire. Furthermore, IP's cash balance grew by more than $X X million from October 20, 2008 (the day before IP borrowed from Ameren) to October 22, 2008 (the day before IP issued $400 million bonds), as shown on Appendix G. This indicates that IP did not use the proceeds from the Ameren loan, making it dubious whether IP needed the Ameren loan at all.[26] (Staff Ex. 19.0R, pp. 8-9)

The AIU argue further:

> First, AmerenIP's long-term debt issuance was not impacted by its temporary short-term money pool loan to AmerenCIPS. AmerenIP sized the debt issuance to retire its own short-term debt with an objective of maintaining an <u>appropriate level of available liquidity</u>…the money pool loan to AmerenCIPS was simply a temporary use of funds which would have otherwise been maintained as highly liquid short-term investments as a liquidity reserve. (Ameren Ex. 28.0, pp. 5-6, <u>emphasis added</u>)

The AIU never quantify an "appropriate level of liquidity." (Staff Ex. 19.0R, p. 10 and Attach. D) Furthermore, it is not clear what prompted IP to issue $50 million more long-term debt than required to repay its short-term bank loans. One-year financial projections for IP, dated September 18, 2008, show that X X X X X X X X X X X X X X X X

[26] Given IP never used the proceeds from the Ameren loan, IP could have simply returned the proceeds from the Ameren loan back to Ameren. For this reason, Staff suspects the objective of the extra $50 million bonds IP issued was not to retire the loan from Ameren, but to increase its 9.75% bond issuance to $400 million. That is, IP likely devised the Ameren loan to facilitate the bond issuance because the Commission's Order in Docket No. 08-0565, which authorized IP's debt issuance, required IP to issue up to $400 million for the purpose of refunding outstanding indebtedness. If IP's outstanding short-term indebtedness had been $343 million on October 22, 2008, IP could have legally issued only $350 million in bonds, including deductions for expenses and issuance discounts. (Order, Docket No. 08-0565, October 15, 2008, pp. 2 and 5) Increasing the amount of short-term debt outstanding to $400 million two days before going to the bond market enabled IP to legally increase the amount of the 9.75% bond issuance to $400 million.

X (Staff Ex. 19.0R, p. 10)

The table below shows CIPS' and IP's liquidity on October 20, 2008, which was one day before IP borrowed money pool funds and three days before IP issued long-term debt totaling $400 million.

Short-Term Debt Balances & Total Available Liquidity on October 20, 2008 (in millions)		
Short-term bank loans	$X X	$X
Money pool borrowings	$X	$X
Total Short-Term Debt Outstanding	**$X X**	**$X**
Surplus funds (i.e., loans to money pool)	$X	$X
Cash	$X	$X
Unused bank facility capacity	$X	$X X
Total Available Liquidity	**$X**	**$X X**

While CIPS had borrowed $X X million from the money pool, it had no outstanding bank loans, surplus funds or cash, leaving CIPS with $X X million in total available liquidity. (Staff Ex. 5.0R, p. 29) That is, on October 20, 2008, CIPS' short-term debt balance was less than IP's and CIPS' total available liquidity was higher. Nevertheless, IP issued

$50 million more long-term debt than required for IP's utility operations and CIPS continued to rely upon low cost money pool funds rather than issue any long-term debt during 2008. (Staff Ex. 5.0, pp. 29-30)

The Company argues further that IP needed substantial cash balances for two reasons. First, IP alleges it does not have ongoing cost-effective daily access to same-day funds for uncertain working capital needs due to the three-day lag between when it requests a LIBOR loan and when the banks fund the LIBOR loan. IP also claims that it commonly holds cash to fund payment requirements on a daily basis and to be ready to fund cash collateral requirements, which can change on a daily basis. Neither argument is compelling.

First, the three-day lag on LIBOR loans has been a requirement since the AIU entered the 2006 credit facility. It is not new to the AIU and is not unique to IP. (Staff Ex. 5.0R, p. 27) Furthermore, the pricing schedule for the AIU credit facility mirrors the pricing schedule for Ameren's non-utility credit facility, including an "ABR spread" that applies to same-day loans. (Staff Ex. 20, Attach. A; Staff Group Cross Ex. 1-F) Staff notes the ABR rate would have to be 673 basis points higher than current cost of short-term bank loans for the AIU (3.02%) before it would be as costly as IP's 9.75% bonds. Over the long-term, the ABR rate would be less costly than IP's 10-year bonds because borrowers may prepay ABR loans without premium or penalty. (Staff Group Cross Ex. 1-F) In contrast, IP locked in the 9.75% rate for ten years.

Second, AIU never explain why its working capital and cash collateral requirements are not predictable. The AIU provide no evidence that the Companies are unaware of upcoming due dates for the services and goods it purchases such that substantial calls for cash payments can occur on fewer than three-days' notice. To the contrary, the record contains evidence that there are no significant surprise calls for cash. None of the contractual obligations for which IP received three days or fewer notice during October 2008 was larger than $5 million. (Staff Group Cross Ex. 1-G) On that date, IP had approximately $57 million of available liquidity.[27] Notwithstanding the facts, assuming there were significant surprise calls for cash for the AIU, then the AIU would never have allowed CIPS to carry less than $1 million cash balances (including contributions to the money pool) from October 17, 2008 through March 31, 2009, as shown on Appendix G.[28]

IP also claims it needed to issue excess high cost long-term debt due to the financial crisis:

> Finally, particularly during the period September 2008 through December 2008, the financial crisis was at its worst with no signs of if and when financial conditions would begin to improve. Lehman Brothers declared bankruptcy on September 15th and rumors swirling about the health of other financial institutions including lenders in the AIUs' credit facilities. Net available liquidity to the AIUs' was as low as $99 million in September. AmerenIP, similar to other borrowers, began to conservatively and proactively manage its own liquidity – prudent under the circumstances – by maintaining larger cash balances. (Staff Ex. 5.0R, p. 28, citing AIU response to Staff DR RP 1.20)

The AIU argument has two flaws: First, its reference to the $99 million liquidity available to the AIU under the credit facilities on September 25, 2008 ignores the AIU's aggregate cash balance of $X X million. That is, total available liquidity for the AIU was $X X million on September 25, 2008, not $99 million. (Staff Ex. 5.0R, p. 28) Second, it ignores the fact that of the three AIUs, only one issued excess debt at high cost. That is, the AIU never explained why a financial crisis that warrants IP issuing an extra $50

[27] The $57 million of available liquidity comprises $X X million unused capacity under credit facilities, plus $X million money pool contributions, plus $X X million cash. (Staff Group Cross Ex. 1, "O'Bryan WP 2")
[28] On October 23, 2008, CIPS' cash balance equaled $X X million, as shown on Appendix G.

million of high cost debt is not sufficient for CILCO or CIPS to issue excess high cost debt.

Moreover, two days after the Lehman Brothers bankruptcy filing, September 17, 2008, there was only $21 million of lost borrowing capacity for the AIU under the 2006 credit facility. Furthermore, Ameren and its subsidiaries, including the AIU, did not believe the potential reduction in available capacity under the credit facilities if Lehman Brothers did not fund its commitments would materially affect their liquidity. In fact, on September 18, 2008, Ameren had available liquidity (including cash balances) of approximately $1.197 billion, excluding the $121 million of Lehman Brothers' credit facilities commitments. (Staff Ex. 19.0R, p. 11)

The AIU assert, "[t]he incremental $50 million repaid other short-term indebtedness and further enhanced IP's liquidity position." Mr. Nickloy states:

> Adding to this environment was the fact the Ameren Illinois Utilities' bank facilities were scheduled to expire in January 2010 with no assurance that the bank markets would improve and permit the extension or renewal of these facilities. (Ameren Ex. 28.0, p. 7)

However, IP issued the long-term indebtedness more than one year before the AIU bank facilities would expire. Moreover, IP did not require the $50 million that Ms. Phipps removed from its long-term debt balance to repay existing short-term indebtedness. IP issued more long-term debt than it required in order to "further enhance" its liquidity position by increasing its cash reserves and has not shown it considered any less-costly alternatives to issuing more long-term bonds than it required to repay its short-term bank loans. (Staff Ex. 19.0R, p. 12)

None of IP's reasons for maintaining substantial cash balances warrants IP customers paying 9.75% interest on $50 million in bonds for ten years, the proceeds from which IP earned a return below 0.25% through either a loan to an affiliate or an investment in money market funds. (Staff Ex. 5.0R, p. 28)

d. Common Equity Balance – Contested

For ratemaking purposes, Staff recommends IP's March 31, 2009 common equity balance equals $1,052,636,039. (Staff Ex. 19.0R, Schedule 19.01 IP) The AIU calculation equals $1,110,636,039. (Ameren Ex. 37.1, p. 3)

Ms. Phipps removed from IP's common equity balance a $58 million common equity infusion by Ameren Corporation that occurred during March 2009 in order to bolster IP's equity ratio. This equity infusion bolstered IP's equity ratio after the Company issued $50 million more bonds than necessary to repay its outstanding short-term bank loans. Therefore, Ms. Phipps recommends removing both $50 million long-term debt that IP did not require and the subsequent $58 million equity infusion. (Staff Ex.19.0R, pp. 13-14)

The AIU claim, "[i]gnoring the credit and liquidity enhancing step of making a common equity infusion into IP implies neither of these objectives is worthwhile." (Ameren Ex. 28.0, p. 7) Yet, Staff takes no position on whether those objectives noted by the AIU are worthwhile. Rather, Ms. Phipps contends that if IP had issued $350 million 9.75% bonds during October 2008 instead of $400 million, then bolstering IP's common equity ratio would not have been necessary. Towards that end, the table below shows that the Company's proposed capital structure ratios, which reflects both the $400 million long-term debt issuance and the $58 million equity infusion, is very close to Staff's recommended capital structure, which removes $50 million of the long-term debt issuance and the $58 million equity infusion.

March 31, 2009 Capital Structure Proposals for IP		
	Company	Staff
Long-Term Debt	53.7%	54.1%
Short-Term Debt	0.4%	0.5%
Preferred Stock	1.8%	1.9%
Common Equity	44.1%	43.5%
Total	100.0%	100.0%

(Staff Ex. 5.0R, pp. 32-33) The Company alleges the common equity infusion was a credit enhancing action taken by Ameren and IP that ultimately led to Moody's decision to restore IP's credit rating to investment grade. (Ameren Ex. 28.0, p. 8) However, Moody's August 13, 2009 ratings upgrade announcement does not support the Company's claim. To the contrary, the Moody's report expressly states, "[t]he upgrade of Ameren's Illinois utilities is prompted by the recent execution of new bank facilities and the improved political and regulatory environment for utilities in Illinois. (Staff Ex. 19.0R, p. 13 and Attachment C)

Finally, Mr. Nickloy argues:

> Although the March equity infusion resulted in a temporary increase in cash, this enhanced AmerenIP's liquidity position and reduced the extent to which it would need to rely on its bank facilities. (Ameren Ex. 28.0, p. 8)

Staff counters that IP did not need the cash from the $58 million infusion of common equity during March 2009. Specifically, IP's March 2009 surplus funds balances ranged from $X X million to $X X million (including money pool contributions). Additionally, since IP issued the October 2008 bond issuance, IP has not borrowed under any of its $350 million bank credit facilities or the money pool. That is, during March 2009, IP had at least $X X million to $X X million in available liquidity. (Staff Ex. 19.0R, p. 13) For the foregoing reasons, the Commission should reject the Companies' proposed common equity balance and instead adopt Staff's proposed capital structure for IP.

e. Staff's Alternative Recommendation

Staff recommends the Commission consider the related adjustments to IP's long-term debt and common equity balances together. In terms of capitalization, the March 2009 $58 million common equity infusion essentially offsets the $50 million in excess debt IP issued in October 2008. If IP had issued $50 million less in debt in October 2008, it would not have needed $58 million of common equity in March 2009 to keep its common equity ratio from sinking further. Nevertheless, if the Commission agrees with Staff's adjustment to IP's long-term debt balance, but not the adjustment to IP's common equity balance, then Staff recommends the Commission also not remove from IP's long-term debt balance the $50 million in excess debt IP issued in October 2008.

Specifically, Staff's alternative recommendation is to adjust the interest rate on the $50 million in excess debt to 7.83%, which is IP's embedded cost of long-term debt had the $50 million in excess debt never been issued. This approach would prevent the $50 million of excess debt from increasing IP's embedded cost of long-term debt while still recognizing the equity infusion. Notably, the before tax cost of common equity is more expensive than even 9.75% debt. Therefore, absent Staff's alternative proposal, IP's before-tax rate of return on rate base would be higher if the Commission only reduced the balance of the October 2008 debt issue than if the Commission adjusted neither the amount of the October 2008 debt issue nor the March 2009 common equity infusion. (Staff Ex. 19.0R, pp. 14-15; Schedules 19.03 and 19.04)

C. Cost of Preferred Stock – Resolved for CILCO, CIPS and IP

Staff and the AIU agree that CILCO's March 31, 2009, embedded cost of preferred stock equals 4.61%; CIPS' December 31, 2008, embedded cost of preferred stock equals 5.13%; and IP's March 31, 2009, embedded cost of preferred stock equals 5.01%. (Staff Ex. 19.0, Schedule 19.01 CILCO, 19.01 CIPS and 19.01 IP; Ameren Ex. 37.1)

D. Cost of Long-Term Debt

1. CILCO – Contested

For ratemaking purposes, CILCO's March 31, 2009 embedded cost of long-term debt equals 6.69%. (Staff Ex. 19.0R, Schedule 19.01 CILCO) The AIU calculation equals 8.16%. (Ameren Ex. 37.1, p. 1)

In accordance with Staff's understanding of Section 9-230 of the Act, Ms. Phipps adjusted the coupon rate for CILCO's 8.875% bonds to reflect the low business risk profile of CILCO's electric and gas delivery service operations. Moody's, S&P and Fitch Ratings recognize that non-utility affiliates affect CILCO's credit rating. Specifically, Moody's states:

> CILCO's rating is constrained by the relatively high level of debt at CILCORP, which exhibits significantly lower financial metrics on a consolidated basis than its utility subsidiary…CILCO's metrics are also likely to be pressured by an anticipated increase in environmental capital expenditures at its subsidiary AERG…

S&P states:

> Of particular concern is the large capital expenditures required at the unregulated companies needed to meet environmental compliance standards, while relying on falling market prices, due to the economic recession, for recovery. Due to these concerns, Standard & Poor's lowered the business risk profile of CILCO to 'satisfactory' from 'strong.'

Fitch states:

> The ratings also consider the substantial earnings and cash flow contribution and merchant risk of CILCO's unregulated wholesale power subsidiary AmerenEnergy Resources Generating Co. (AERG) AERG is subject to greater cash flow volatility than CILCO's regulated transmission and distribution businesses and increase overall business risk.

Despite the rating agencies' comments confirming that CILCO's affiliation with CILCORP and AERG increase CILCO's business risk, the AIU have not performed any analyses regarding the effect of CILCO's affiliation with CILCORP and AERG on the 8.875% coupon rate for CILCO's December 2008 bond issuance. (Staff Group Cross Ex. 1-H) Thus, Ms. Phipps removed the incremental risk in CILCO's credit ratings resulting from its non-utility affiliates using the following methodology.

Regarding Moody's ratings, Ms. Phipps considered that during December 2008, CILCO's issuer rating from Moody's was Ba1 and its senior secured debt rating was Baa2. Moody's classified CILCO as having "Medium" business risk, which is typical for integrated utilities. In contrast, Moody's viewed U.S. transmission and distribution utilities' business risk as "Low." Therefore, by evaluating Moody's rating factors for CILCO using the benchmarks for low business risk electric utilities, Ms. Phipps concluded CILCO's implied issuer rating would be Baa1 for its regulated utility operations. Since CILCO's secured debt rating is two notches above its unsecured ratings, she concluded that Moody's would assign CILCO a secured debt rating of A2 of non-utility affiliates had not increased its business risk. (Staff Ex. 5.0R, pp. 15-16)

Regarding S&P ratings, Ms. Phipps evaluated CILCO's implied standalone S&P credit rating using financial ratios published by S&P, combined with a "Strong" business risk profile rather than CILCO's actual business risk profile of "Satisfactory." The S&P Business Risk / Financial Risk Matrix ("S&P rating matrix") indicates CILCO's current

"BBB-" issuer rating is consistent with a "Satisfactory" business risk profile and CILCO's standalone financial ratios, as calculated by S&P. Using the S&P rating matrix, Ms. Phipps concluded that changing CILCO's business risk profile to "Strong," would likely raise its issuer rating to BBB+. Since CILCO's current S&P secured debt rating is two notches above its issuer rating, she estimates S&P would assign CILCO a secured debt rating of A if its business risk profile was not affected by its riskier non-utility affiliates. (Staff Ex. 5.0R, pp. 16-17)

Finally, using CILCO's implied, low business risk, senior secured ratings of A2/A, Ms. Phipps estimated a coupon rate for CILCO's December 2008 bonds. Specifically, she reviewed A-rated, secured, electric utility debt financings with five-year terms to maturity that occurred between September 25 and December 31, 2008 (*i.e.*, following the Lehman Brothers bankruptcy). At that time, five-year, A-rated secured electric utility bonds were yielding 6.24%. (Staff Ex. 5.0R, p. 17)

The AIU claim, "AmerenCILCO needed to complete this refinancing in order to reduce borrowings under its bank facilities…and improve its liquidity position." Staff contends this is a red herring. Ms. Phipps did not argue that CILCO should not have issued $150 million long-term indebtedness. Her adjustment is limited to removing any incremental cost of CILCO's capital due to its non-utility affiliates, as required by Section 9-230 of the Act. (Staff Ex. 19.0R, pp. 2-3)

Second, the AIU claim, "Ms. Phipps does not offer any compelling evidence that AmerenCILCO's rating, or the coupon/interest rate on this debt offering, would have been any different than what either was at the time this debt was issued." Staff observes that AIUs' decision to purchase the credit rating services of Standard & Poor's, Moody's and Fitch Ratings belies its contention that the opinions of those credit ratings agencies do not constitute compelling evidence. In fact, each of the rating agencies notes that CILCO's non-utility affiliates (*e.g.*, AERG's riskier generation operations and CILCORP's direct indebtedness) affect its credit rating. Therefore, Ms. Phipps compared the financial metrics that Moody's publishes for CILCO to Moody's benchmarks for a "Low" business risk profile (*i.e.*, a transmission and distribution company) rather than a "Medium" business risk profile (*i.e.*, an integrated utility) to estimate Moody's implied utility-only issuer credit rating for CILCO. Similarly, she compared the financial metrics that S&P publishes for CILCO to a less risky business profile than S&P has assigned to CILCO to estimate S&P's implied utility-only issuer credit rating for CILCO. Specifically, she concluded S&P would assign CILCO a "Strong" business risk profile, which is the business risk profile that S&P has assigned CIPS and IP. Specifically, S&P states the following regarding CIPS' and IP's business profiles:

> IP's ratings also reflect its strong business profile and Ameren's significant financial profile…IP's strong business profile reflects its lower operating risk. As a distributor with no owned generation, IP has less operating risk than a fully integrated utility.
>
> ***
>
> CIPS' ratings also reflect its strong business profile and Ameren's significant financial profile…CIPS' strong business profile reflects its lower operating risk. As a distributor with no owned generation, CIPS has less operating risk than a fully integrated utility.

In contrast, with respect to CILCO, S&P states:

> CILCO's ratings also reflect its satisfactory business profile and Ameren's significant financial profile. CILCO's satisfactory business profile reflects its non-regulated businesses, partially offset by its lower risk regulated transmission and distribution business.

(Staff Ex. 19.0R, pp. 3-4)

According to the AIU, actual ratings could span one notch above or below the midpoint indicated on the S&P rating matrix and argue this means CILCO's rating using a "Strong" business risk profile could still be BBB- (CILCO's actual rating) rather than BBB+ (CILCO's adjusted rating). Yet, the first step in making Ms. Phipps' adjustment to CILCO's S&P rating was plotting CILCO's actual S&P issuer rating on the matrix using the "Significant" financial risk profile and the "Satisfactory" business risk profile that S&P actually assigns CILCO. Next, without changing where CILCO's rating falls on the financial risk spectrum, Ms. Phipps moved CILCO's business risk profile up one category to "Strong." Thus, Ms. Phipps only changed business risk profile; everything else she held the same. Consequently, the Company's argument implies that, all else equal, a change of business profile alone could be insufficient to induce S&P to alter its credit ratings. However, that S&P decided to disclose what CILCO's business profile would be in the absence of AERG and CILCORP's indebtedness indicates that information is sufficient to affect CILCO's credit ratings. To assume the contrary, implies that S&P clutters its otherwise concise reports with immaterial information. (Staff Ex. 19.0R, pp. 4-5)

Finally, AIU witness Mr. Nickloy states:

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However, Moody's, S&P and Fitch Ratings have never stated their review of CILCO's financial performance is indicative of the standalone, regulated utility, without the presence of any unregulated subsidiaries. The August 14, 2009, Moody's ratings report for CILCO includes financial metrics for the twelve months ended June 30, 2009 and years 2006-2008. (Staff Ex. 19.0R, pp. 5-6)

Despite the X X X X X X X X X X X X X X X X X X X and contrary to Mr. Nickloy's claim, the August 14, 2009, Moody's report notes that Cilcorp's debt and AERG's non-utility operations affect CILCO's credit rating. Specifically, Moody's states:

> AmerenCILCO…also includes the unregulated generation subsidiary AmerenEnergy Generating Company (AERG), which is unrated…CILCO's financial metrics are very strong for its rating…CILCO's rating is constrained by $210 million of long-term debt at its intermediate parent company CILCORP, which exhibits significantly lower financial metrics on a consolidated basis than its utility subsidiary…AmerenCILCO is unique among Ameren's three Illinois utilities in that it owns AERG, with 1,200 MW of unregulated generation, consisting of AmerenCILCO's former generating assets. AERG has significant capital expenditure requirements necessary to bring it into compliance with current environmental standards.

In any event, it is not clear why the rating agencies would view CILCO as a standalone regulated utility since the AIU are not certain when CILCO would spin-off AERG. Further, it would say little for the supposed independence of the ratings agencies if they accepted without question the financial ratios provided by debt issuers. (Staff Ex. 19.0R, p. 6)

For all the foregoing reasons, Staff's recommended costs of CILCO's long-term debt for ratemaking purposes, should be adopted.

2. CIPS – Resolved

Staff and the AIU agree that for the purpose of this case, CIPS' December 31, 2008, embedded cost of long-term debt equals 6.49%. (Staff Ex. 19.0R, Schedule 19.01 CIPS; Ameren Ex. 37.1, p. 2) CIPS' embedded cost of long-term debt reflects Staff's adjustment to remove any incremental cost increase due to the Company's decision to refinance the 4.7% intercompany note with 6.7% bonds during June 2006.

The Commission adopted this adjustment to CIPS' embedded cost of long-term debt in the AIU's most recent rate cases, Docket Nos. 07-0585 through 0590 (Cons.). (Staff Ex. 5.0R, pp. 21-22) For the purposes of the instant case, the Company accepted Staff's adjustment. (Ameren Ex. 37.0 (Revised), p. 3)

3. IP – Contested

Staff's calculation of IP's March 31, 2009 embedded cost of long-term debt equals 7.83%. (Staff Ex. 19.0R, Schedule 19.01 IP) Under Staff's alternative proposal for IP's capital structure, as described previously, IP's embedded cost of long-term debt also equals 7.83%. (Staff Ex. 19.0R, Schedule 19.03) The AIU proposes a 7.94% embedded cost of long-term debt for IP. (Ameren Ex. 37.1, p. 3) The only contested issue between Staff and the AIU relating to IP's long-term debt is the previously described adjustment that Staff made to the amount of IP's 9.75% bonds issuance, which also affects IP's embedded cost of long-term debt.

E. Cost of Short-Term Debt including Bank Commitment Fees

<u>Cost of Short-Term Debt before Bank Commitment Fees</u>

The AIU short-term debt balances comprise either bank loans, money pool borrowings, or both. IP's short-term debt balance comprises 100% bank loans, whereas CILCO's and CIPS' short-term debt balances included short-term borrowings at the bank loan rate (*i.e.,* bank loans and externally raised money pool loans) and the AA Non-Financial commercial paper rate (*i.e.,* internally generated money pool loans). Hence, Ms. Phipps calculated a weighted-average cost of short-term debt for CILCO and CIPS based upon the proportion of their short-term debt balances that comprised borrowings at the bank loan rate and the rate for internally generated money pool loans. (Staff Ex. 5.0R, pp. 5-6)

IP, CILCO and CIPS obtain short-term loans under the same credit agreement (the "Illinois credit facility" or "Illinois Facility"). Ms. Phipps' bank loan interest rate calculation begins with the 0.2725% one-month LIBOR rate on August 18, 2009, plus the applicable margin, which varies according to the borrower's senior secured credit rating. Currently, CILCO and CIPS have senior secured credit ratings of Baa1/BBB+ from Moody's and S&P whereas IP has senior secured credit ratings of Baa1/BBB from Moody's and S&P. According to the Illinois credit facility, the AIU are Level III borrowers and pay a 2.75% margin over LIBOR. Thus, Ms. Phipps calculated a 3.02% bank loan interest rate for CIPS and IP, before bank commitment fees. (Staff Ex. 5.0R, pp. 6-7) For CILCO, Ms. Phipps relied upon CILCO's actual senior secured debt rating from Moody's (Baa1) and her estimate of CILCO's S&P rating, adjusted solely to reflect a lower degree of business risk (A).[29] Pursuant to the Illinois credit facility, CILCO's implied Baa1/A ratings would result in a Level II borrower status, and would require paying a 2.375% margin over LIBOR. For rate setting purposes, CILCO's current bank loan rate equals 2.65% before bank commitment fees. (Staff Ex. 19.0R, p. 7)

Additionally CILCO's and CIPS' short-term debt balances include money pool loans borrowed at the internal money pool rate, which equals the AA Non-Financial commercial paper rate, or 0.19%. (Staff Ex. 5.0R, pp. 14 and 20) During the short-term debt measurement period, 94% of CILCO's short-term borrowings were at the bank loan rate and 6% were at the internal money pool rate. (Staff Ex. 5.0R, p. 14) Thus, CILCO's weighted average interest rate for short-term debt equals 2.50%. (Staff Ex.

[29] During August 2009, Moody's revised its credit rating methodology. The new methodology does not provide distinguishable business risk categories that permit evaluating financial metrics for a "Medium" risk utility that owns generation versus a "Low" risk distribution utility. Therefore, Ms. Phipps relied upon CILCO's actual senior secured debt rating from Moody's to estimate CILCO's cost of short-term debt. (Staff Ex. 19.0R, p. 7)

19.0R, p. 7) During the short-term debt measurement period, 46% of CIPS' short-term borrowings were at the bank loan rate and 54% were at the internal money pool rate. Thus, the weighted average interest rate for CIPS' short-term debt equals 1.50%. (Staff Ex. 5.0R, p. 20) Since IP's short-term debt balances do not include any money pool loans borrowed at the internal money pool rate, IP's cost of short-term debt equals the Company's 3.02% bank loan rate. (Staff Ex. 5.0R, p. 24)

Bank Commitment Fees

Ameren established two credit facilities in June 2009 - the $800 million Illinois credit facility, which covers the AIU and Ameren (the "Illinois Facility"), and the $1,150 million amended and restated credit facility that covers Union Electric Company, Ameren Energy Generating Company and Ameren (the "Missouri Facility"). (Staff Ex. 5.0R, p. 7)

Staff recommends allocating annual costs of $1,467,431 to CILCO; $1,453,649 to CIPS; and $3,768,782 for IP. (Staff Ex. 19.0R, Schedule 19.05) Ms. Phipps derived those amounts by reducing the amount of upfront fees from $15,505,000 to $12,205,000 and allocated 62.5% of all fees to the AIU. (Staff Ex. 19.05R, Schedule 19.05; Ameren Ex. 37.4) Further, she reduced the facility fees for CILCO to reflect its standalone S&P credit rating and for IP to reflect its' Moody's credit rating upgrade during August 2009. In contrast, the AIU allocated 67.9% of the fees to the AIU, including $15,505,000 in upfront fees. (Ameren Ex. 37.4) Staff calculated the cost of bank commitment fees that should be added to each Company's cost of capital by dividing each Company's total bank commitment fees by total capitalization. Hence, Staff recommends adding 28 basis points to CILCO's overall cost of capital; 15 basis points to CIPS' overall cost of capital; and 16 basis points to IP's overall cost of capital. (Staff Ex. 19.0R, Schedule 19.05)

Staff calculated bank commitment fees for the Illinois credit facility and allocated those fees between the AIU and Ameren based on Section 9-230 of the Act, which states:

> In determining a reasonable rate of return upon investment for any public utility in any proceeding to establish rates or charges, the Commission shall not include *any*… increased cost of capital… which is the direct or indirect result of the public utility's affiliation with unregulated or nonutility companies. (emphasis added)

In this section of the Act, the legislature used the word *any* to modify its prohibition of considering increased cost of capital in determining a reasonable rate of return. This language prohibits the Commission from considering what portion of a utility's increased cost of capital caused by an affiliation caused by an affiliation is reasonable and therefore should be borne by ratepayers. The 2nd District Appellate Court, in the case of *Illinois Bell Telephone Co. v. Illinois Commerce Comm'n*, 283 Ill. App. 3d 188, 207, 218 Ill. Dec. 598, 669 N.E.2d. 919 (1996), has held that — if a utility's exposure to risk is one iota greater, or if it pays one dollar more for capital because of its affiliation with an unregulated or nonutility company, the Commission must take steps to ensure that such increases do not enter in its rate of return calculation. Therefore, it would be illegal to reflect <u>any</u> resulting incremental cost increase in the AIUs' cost of capital, even one iota greater, regardless of any potential benefits of either jointly negotiating the Illinois and Missouri credit facilities or including Ameren as a borrower under the Illinois credit facility. Thus, Staff's calculation of the AIU bank commitment fees must be adopted as a matter of law.

Nevertheless, the AIU object to Ms. Phipps' calculation of the amount of upfront fees, which removed any incremental cost resulting from higher upfront fees based on aggregate commitment under the Illinois and Missouri Facilities combined than would result from the Illinois Facility commitments only. Second, the AIU object to Ms. Phipps' allocation of bank commitment fees between Ameren and the AIU because she reduced the combined AIU sub-limit to $500, which is the maximum borrowing capacity that would be available to the AIU whenever Ameren borrows at its $300 million maximum sublimit under the Illinois Facility.

Upfront Fees

Ms. Phipps calculated one-time upfront fees for the AIU to maintain their bank lines of credit, which vary from 1.5% to 2.0% of the aggregate amount of each lender's commitments under both the Illinois and Missouri Facilities and increase as the commitment amount increases. Ms. Phipps calculated upfront fees of $12,205,000, based on each lender's commitments under the Illinois Facility only because Section 9-230 of the Act prohibits including in a utility's allowed rate of return any increased cost of capital, which is the direct or indirect result of the public utility's affiliation with unregulated, or non-utility companies. (Staff Ex. 5.0R, pp. 7-8)

The AIU allege that Ms. Phipps' calculation of the AIU bank commitment fees assumes the upfront fees would be lower if the total facility size is lower. Mr. O'Bryan argues, "[i]t would be wrong to suggest that banks would be willing to lend into a smaller (Illinois only) facility at a 1.50% rate." He notes that allegedly "smaller" credit facilities recently completed by Integrys Energy Group ($500 million) and NiSource ($265 million) included upfront fees of 2% for all borrowers. (Ameren Ex. 37.0 (Revised), pp. 4-5) However, those comparisons have no value. Mr. O'Bryan's argument implies those facilities are similar to the Illinois Facility; however, they were entered into prior to the date AIU closed on the Illinois credit facility and the amount of each of the credit facilities lenders' commitments to the borrowers is unknown. Towards that end, the smaller bank facility for Integrys Energy Group that Mr. O'Bryan references actually replaced a small portion of Integrys Energy Group's aggregate $2.2 billion credit facilities. Consequently, we do not know whether the Integrys Energy Group upfront fee reflects the bank's aggregate commitment of $2.2 billion or the incremental commitment of $500 million.[30] The other electric utility that Mr. O'Bryan references, NiSource, Inc., is distinguishable from the Illinois Facility because NiSource, Inc. entered a term bank loan to supplement $1.5 billion revolving credit facilities. (Staff Ex. 19.0R, p. 16) A term bank loan is not a credit facility.

Mr. O'Bryan argues that there is no reason the Illinois Facility should have a lower upfront fee than the larger aggregate Ameren facilities. (Ameren Ex. 59.0, p. 2) Mr. O'Bryan's argument implies there are economies of scale associated with a larger credit facility. To the contrary, under the terms of the Illinois Facility, upfront fees increase as commitment amounts increase. (Staff Ex. 19.0R, pp. 16-17)

Allocation of Commitment Fees to AIU

Ms. Phipps divided one-time costs between the AIU and Ameren according to borrower sub-limits under the Illinois Facility (*i.e.,* $150 million for CILCO, $135 million for CIPS, $350 million for IP and $300 million for Ameren). The borrower sub-limits total $935 million; however, combined Illinois Facility borrowings cannot exceed $800 million.

[30] The upfront fees Ameren and its affiliates pay reflect the banks' aggregate commitment for both the Illinois and Missouri credit facilities rather than the banks' separate commitments to the two facilities independently. Mr. O'Bryan did not explain why banks would set the upfront fee for the Integrys Energy Group credit facilities in a different manner than the banks set the upfront fee for the Ameren Missouri and Illinois bank facilities.

Given Ameren can borrow up to $300 million, the Illinois credit facility could at times effectively reduce the AIU sub-limits to $500 million, or 62.5% of the $800 million Illinois Facility. On this basis, she allocated $1,000,000 arrangement fees, $7,628,125 upfront fees, and $23,438 annual administrative agency fees to the combined AIU. (Staff Ex. 5.0R, p. 8; Staff Ex. 19.0R, p. 15)

The AIU allege that Ms. Phipps' calculation assumes that Ameren will consistently borrow up to its sublimit of $300 million over the life of the Illinois Facility and, therefore, Staff's methodology assigns too much cost to Ameren and too little to the AIU. (Ameren Ex. 37.0 (Revised), p. 6) However, without Staff's adjustment, the AIU, and ultimately AIU customers, would pay costs associated with more credit facility capacity than they would have available if Ameren borrows more than $165 million under the Illinois credit facility. (Staff Ex. 19.0R, p. 17) This is more than a hypothetical constraint on the borrowing capacities of the AIU because during July and August 2009, Ameren borrowed $X X million under the Illinois Facility, effectively reducing the AIU borrowing capacity to $X X million. (Staff Ex. 5.0R, p. 11; Staff Group Cross Ex. 1-A)

The AIU assert that Staff's methodology does not recognize that Ameren may borrow under the facility to provide the AIU supplemental liquidity by acting as their "lender of last resort" when the AIU are at their maximum of their individual borrowing sub-limits and there are no money pool funds available. However, this argument does not support the Companies' claim that the AIU should pay costs associated with the $135 million borrowing capacity that either the AIU or Ameren could borrow. The AIU argument applies only to borrowing capacity over the aggregate AIU sub-limit of $635 million because, under the Illinois Facility, Ameren pays a higher short-term bank loan rate than any of the AIU due to its Baa3/BBB- unsecured debt ratings from Moody's and

S&P. Consequently, it makes no sense for Ameren to borrow from the Illinois Facility and then lend the proceeds to the AIU. Regardless, the Commission's rules for utility money pool agreements prohibits utilities borrowing from affiliates whenever utilities may borrow at lower cost directly from banks or other financial institutions. Therefore, Ameren can only act as the AIUs' "lender of last resort" when the AIU reach their maximum, aggregate borrowing capacity of $635 million. (Staff Ex. 19.0R, pp. 17-18)

AIU witness Mr. O'Bryan asserts further:

> Ameren has access to $1.3 billion of credit facilities outside the Illinois Facility at a rate that is slightly lower than the rate it can borrow from the Illinois Facility. Therefore it has a financial incentive to borrow from the other facilities. (Ameren Ex. 59.0, p. 4)

Mr. O'Bryan's assertion deceptively implies that Ameren can borrow $1,150,000,000 – its entire sub-limit under the Missouri credit facility – for the entire two-year term of the Missouri credit facility at lower cost than Ameren can borrow from the Illinois facility. This deception occurs because Mr. O'Bryan neglects to reveal that these lower borrowing costs are available only from "Declining Lenders" through July 14, 2010. "Declining Lenders" are those lenders under the original Missouri Facility that declined the option to extend their original commitments beyond July 14, 2010. (Staff Group Cross Ex. 1-F)

Amending and restating the 2006 and 2007 Illinois credit facilities would have benefited the AIU by making lower borrowing rates available from Declining Lenders. For example, under the prior facility's pricing schedule, the spread over LIBOR for a Level III borrower equals 0.60%. (AmerenCILCO Ex. 13.0E, pp. 6-7; AmerenCILCO Ex. 13.0G, pp. 6-7) In contrast, the current spread over LIBOR for a Level III borrower equals 2.75%. (Staff Group Cross Ex. 1-F) Yet, Ameren terminated the 2006 and 2007 Illinois credit facilities seven months before they expired.

Moreover, Ameren is not obliged under any agreement to provide the AIU supplemental liquidity; in fact, Ameren has taken steps to insulate itself from the AIU when the Illinois Legislature was considering rate freeze legislation. Specifically, Ameren removed the AIU as borrowers under Ameren's credit facility and removed provisions from the credit agreement that would treat the AIU as subsidiaries for purposes of cross-default provisions. (Staff Ex. 19.0R, p. 18)

Finally, AIU ignores the rationale for a commitment fee, which as its name implies, compensates banks for making a firm commitment to provide up to a specified amount of credit on demand. That is, the full commitment fee applies regardless of the amount of money borrowed or letters of credit issued by each borrower. Nevertheless, because of the overlapping sub-limits in the Illinois credit facility (*i.e.*, the sum of the sub-limits exceeds the total commitment), the commitment available to the AIU is a function of the amount of credit already committed to Ameren. Therefore, the AIU can only count on $500 million of the Illinois credit facility, not the $635 million of their combined sub-limits would otherwise suggest. Thus, only $500 million of the Illinois credit facility is "firm." The remaining $135 million of the combined sub-limits is "interruptible" by Ameren. (Staff Ex. 19.0R, p. 18)

<u>CIPS and IP Facility Fee Adjustment</u>

According to the AIU, adjusting the facility fee rates for CIPS and IP in response to Moody's ratings upgrades for the AIU on August 13, 2009 is improper. (Ameren Ex. 37.0 (Revised), p. 8)

First, Staff notes that prior to the August 2009 rating upgrade by Moody's, CIPS was a Level III borrower and IP was a Level IV borrower. (Staff Ex. 19.0R, p. 19) The Moody's upgrade did not change CIPS' Level III borrower status, but raised IP's borrower status to Level III from Level IV.

Second, using IP's current senior secured credit rating is not a selective adjustment to the cost of capital, as AIU alleges. Staff explained that the adjustment is not the consequence of an out-of-measurement period change in capitalization, such as the issuance of new debt or common equity, the retirement of debt or the payment of common dividends. Selective capital structure adjustment such as those would be improper because they wrongly imply those events occur in isolation. For example, removing a debt issue that matures after the capital structure measurement date fails to consider whether the utility will need to raise capital to refund the maturing debt issue much less what type of capital it will raise. In contrast, the facility fees will change during the term of the credit agreement as each borrower's credit rating changes. The change in the fee rate does not significantly affect the amount of capital the utility needs to maintain. Thus, adjustable facility fee rates are similar to variable interest rates, which the Commission has estimated using current rates rather than those that were in effect during an historical measurement period.

Finally, if the Companies' argument had any merit, which it does not, then AIU cost of capital could not reflect any costs associated with the 2009 Illinois credit facility because the AIU were borrowers under the 2006 and 2007 credit facilities on the capital structure measurement dates. (Staff Ex. 19.0R, pp. 19-20)

1. CILCO - Contested

For ratemaking purposes, Staff recommends a 2.50% cost of short-term debt for CILCO, which Staff revised from its original 2.15% recommendation. (Staff Ex. 19.0R, p. 7 and Schedule 19.01 CILCO) The AIU rebuttal proposal includes a 2.15% cost of short-term debt for CILCO, which AIU updated from its original 1.136% recommendation. (Ameren Ex. 37.1, p. 1; AmerenCILCO Ex. 13.1) Nevertheless, the AIU oppose Staff's adjustment to CILCO's standalone credit rating, which serves as the basis for Staff's original 2.15% recommendation and Staff's final 2.50% recommendation for CILCO's cost of short-term debt. Therefore, it is not clear what cost of short-term debt the AIU recommend for CILCO.

2. CIPS – Resolved

Staff and the AIU agree that CIPS' cost of short-term debt equals 1.50%. (Staff Ex. 19.0R, Schedule 19.01 CIPS; Ameren Ex. 37.1, p. 2)

3. IP – Resolved

Staff and the AIU agree that IP's cost of short-term debt equals 3.02%. (Staff Ex. 19.0R, Schedule 19.01 IP; Ameren Ex. 37.1, p. 3)

F. Cost of Common Equity

1. Resolved Issues

2. Contested Issues

a. Return on Equity Estimates

The table below presents Staff witness Janis Freetly's estimates of the investor-required rates of return on common equity for the natural gas distribution and electric delivery service operations for the AIU. (Staff Ex. 20.0, pp. 1-2 and Schedule 20.02)

	CILCO		CIPS		IP	
	Gas	Electric	Gas	Electric	Gas	Electric
Sample DCF	9.79%	10.67%	9.79%	10.67%	9.79%	10.67%
Sample CAPM	9.46%	10.21%	9.46%	10.21%	9.46%	10.21%
Sample Average	9.63%	10.44%	9.63%	10.44%	9.63%	10.44%
Adjustments						
Financial Risk	0.11%	-0.06%	-0.15%	-0.30%	0.11%	0.00%
Fixed Customer Charge	-0.10%	0.00%	-0.10%	0.00%	-0.10%	0.00%
Recommended Cost of Equity						
Before Uncoll. Rider Adjustment	**9.64%**	**10.38%**	**9.38%**	**10.14%**	**9.64%**	**10.44%**
Uncoll. Rider Adjustment	-0.88%	-0.63%	-0.80%	-0.65%	-0.61%	-0.34%
Including Uncoll. Rider Adjustment	8.76%	9.75%	8.59%	9.50%	9.03%	10.10%

Ms. Freetly measured the investor-required rate of return on common equity with the non-constant discounted cash flow ("DCF") and Capital Asset Pricing Model ("CAPM") analyses. For the AIU gas utilities, Ms. Freetly applied those models to the same sample of nine local gas distribution companies utilized by AIU witness Kathleen McShane. (Staff Ex. 6.0, p. 3) For the AIU electric utilities, Ms. Freetly began with Ms. McShane's sample of electric utilities but eliminated the electric companies the Edison Electric Institute categorized as "Mostly Regulated" since her return on common equity recommendation is for the regulated electric operations of the AIUs. Next, she eliminated the companies that were not assigned an industry classification code of 4911 or 4931 within Standard & Poor's ("S&P") Utility Compustat. Then, she removed companies that are or recently have been involved in mergers, acquisitions, or divestures. Finally, she removed companies that lacked growth rate estimates from Zacks Investment Research ("Zacks") or the data necessary to calculate beta. The remaining sixteen regulated electric utilities compose Ms. Freetly's Electric sample. (*Id.*, pp. 3-4)

<u>DCF Analysis</u>

DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments to the holders of that stock. Since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that a stock price embodies. The companies in Ms. Freetly's Gas and Electric samples pay dividends quarterly. Therefore, Ms. Freetly employed a multi-stage non-constant-growth DCF model that reflects a quarterly frequency in dividend payments. (*Id.*, pp. 4-6)

Staff witness Freetly modeled three stages of dividend growth. The first, near-term growth stage is assumed to last five years. The second stage is a transitional growth period lasting from the end of the fifth year to the end of the tenth year. The third or "steady-state" growth rate is assumed to begin after the tenth year and continue into perpetuity. (*Id.*, pp. 7-8)

For the first stage, Ms. Freetly used market-consensus expected growth rates published by Zacks as of August 18, 2009. To estimate the long-term growth expectations for the third, steady-state stage, she utilized the implied 20-year forward U.S. Treasury rate in ten years, 4.83%. The growth rate employed in the intervening, five-year transitional stage equals the average of the Zacks growth rate and the steady-state growth rate. (*Id.*, p. 8) The growth rate estimates were combined with the closing stock prices and dividend data as of August 18, 2009. Based on these growth assumptions, stock price, and dividend data, Ms. Freetly's DCF estimate of the cost of common equity was 9.79% for the Gas sample and 10.67% for the Electric sample. (*Id.*, p. 11; Staff Ex. 20.0, p. 2)

Risk Premium Analysis

According to financial theory, the required rate of return for a given security equals the risk-free rate of return plus a risk premium associated with that security. The risk premium methodology is consistent with the theory that investors are risk-averse and that, in equilibrium, two securities with equal quantities of risk have equal required rates of return. Staff witness Freetly used a one-factor risk premium model, the CAPM, to estimate the cost of common equity. In the CAPM, the risk factor is market risk, which cannot be eliminated through portfolio diversification. (Staff Ex. 6.0, pp. 11-13)

The CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market. For the beta parameter, Ms. Freetly combined adjusted betas from Value Line, Zacks, and a regression analysis to estimate the beta of the Gas and Electric sample. For the Gas sample, the average Value Line, Zacks, and regression beta estimates were 0.68, 0.56, and 0.51, respectively. For the Electric sample, the average Value Line, Zacks, and regression beta estimates were 0.71, 0.72, and 0.66, respectively. The Value Line regression employs 260 weekly observations of stock return data regressed against the New York Stock Exchange ("NYSE") Composite Index. Both the regression beta and Zacks betas employ sixty monthly observations; however, while Zacks betas regress stock returns against the S&P 500 Index, the regression beta regresses stock returns against the NYSE Index. Since the Zacks beta estimate and the regression beta estimate are calculated using monthly data rather than weekly data (as Value Line uses), Ms. Freetly averaged those results to avoid over-weighting betas estimated from monthly data[31] in comparison to

[31] Hereafter referred to as "monthly betas."

the weekly data-derived Value Line betas.[32] She then averaged the resulting monthly beta with the Value Line weekly beta, which produced a beta of 0.61 for the Gas sample and 0.70 for the Electric sample. (*Id.*, pp. 18-23)

For the risk-free rate parameter, Ms. Freetly considered the 0.14% yield on four-week U.S. Treasury bills and the 4.40% yield on thirty-year U.S. Treasury bonds. Both estimates were measured as of August 18, 2009. Forecasts of long-term inflation and the real risk-free rate imply that the long-term risk-free rate is between 4.3% and 5.2%. Thus, Ms. Freetly concluded that the U.S. T-bond yield is currently the superior proxy for the long-term risk-free rate. (*Id.*, pp. 13-17)

Finally, for the expected rate of return on the market parameter, Ms. Freetly conducted a DCF analysis on the firms composing the S&P 500 Index. That analysis estimated that the expected rate of return on the market was 12.70% for the second quarter of 2009. (*Id*., pp. 17-18) Inputting those three parameters into the CAPM, Ms. Freetly calculated a cost of common equity estimate of 9.46% for the Gas sample and 10.21% for the Electric sample. (*Id.*, p. 23)

<u>Staff Cost of Common Equity Recommendation</u>

Ms. Freetly estimated the investor-required rate of return on common equity for the Gas sample of 9.63% by taking the simple average of the DCF-derived results (9.79%) and the risk-premium derived results (9.46%) for the Gas sample. (*Id.*, p. 24) She then adjusted the Gas sample's investor-required rate of return downward by 15 basis points for CIPS to reflect the lower financial risk of CIPS relative to the Gas sample. She also adjusted the Gas sample's investor-required rate of return upward by 10.5 basis points for CILCO and IP to reflect higher financial risk of CILCO and IP

[32] Hereafter referred to as "weekly betas."

relative to the Gas sample. (Staff Ex. 20.0, p. 6) Next, Ms. Freetly adjusted the Companies' cost of equity downward by 10 basis points to reflect the reduction in risk associated with the recovery of a greater portion of fixed delivery services costs through the monthly customer charge, which was authorized in the Companies' last rate cases.[33] (Staff Ex. 6.0, pp. 24-25) Thus, for the natural gas distribution operations of the Companies, the investor-required rate of return on common equity is 9.64% for CILCO, 9.38% for CIPS and 9.64% for IP. (Staff Ex. 20.0, p. 1)

To estimate the investor-required rate of return on common equity for the electric delivery service operations of the Companies, Ms. Freetly first took the simple average of the DCF-derived results (10.67%) and the risk-premium derived results (10.21%) for the Electric sample, or 10.44%. Then, she adjusted the Electric sample's investor required rate of return downward by 6 basis points for CILCO and 30 basis points for CIPS to reflect the lower financial risk of CILCO and CIPS relative to the Electric sample. Thus, for the electric delivery service operations of the Companies, the investor required rate of return on common equity is 10.38% for CILCO, 10.14% for CIPS, and 10.44% for IP. (*Id.*, pp. 2-3)

Company's Cost of Common Equity Analysis

AIU witness Kathleen McShane estimated the cost of common equity using both the constant growth and non-constant growth DCF models and three equity risk premium analyses. She also applied the comparable earnings test for purposes of assessing the reasonableness of her results. (AmerenCILCO Ex. 12.0 (Revised), p. 24) Based on her updated analysis in rebuttal testimony, for the natural gas distribution

[33] In Docket Nos. 07-0585 – 07-0590 (Cons.), the Commission authorized the AIUs to recover 80% of the fixed delivery services costs of the natural gas operations through the monthly customer charge. (Order, Docket Nos. 07-0585 – 07-0590 (Cons.), Sept. 24, 2008, pp. 215 and 236-238.)

operations, she recommended an 11.2% cost of common equity for CILCO and IP and a 10.8% cost of common equity for CIPS. For the electric delivery service operations, she recommended an 11.7% cost of common equity for CILCO and IP and an 11.3% cost of common equity for CIPS. (Ameren Ex. 36.0, pp. 35-40) Unfortunately, Ms. McShane's analysis contains several errors that led her to over-estimate AIU's cost of common equity. The most significant flaws in Ms. McShane's analysis of the Companies' cost of common equity are her (1) use of historical data in her DCF and risk premium models; (2) inclusion of unwarranted adjustments to the DCF and risk premium results for alleged difference between market value and book value; and (3) inappropriate use of comparable earnings model as a check on her recommended cost of equity. (Staff Ex. 6.0, pp. 48-61)

b. DCF and CAPM Model Issues

<u>Historical Data</u>

The use of historical data is problematic. First, historical data favors outdated information that the market no longer considers relevant over the most-recently available information. Second, historical data reflects conditions that may not continue in the future. In other words, use of average historical data implies that securities data will revert to a mean. Even if securities data were mean reverting, there is no method for determining the true value of that mean let alone the length of time over which mean reversion will occur. Consequently, sample means, which depend upon the measurement period used, are utilized. Thus, any measurement period chosen is arbitrary, rendering the results uninformative.

First, consider Ms. McShane's use of historical data in determining the dividend yield (dividend ÷ stock price) in her DCF model.[34] Since stock prices reflect all current information, only the most recent stock price can reflect the most recently available information. Historical stock prices <u>must</u> include observations that cannot reflect the most current information available to the market. For example, if the actual earnings for a company were much higher than anticipated, the market would react to that news and bid up its stock price. Consequently, the pre-earnings announcement stock prices would reflect obsolete information and understate the value of that company's stock.

Ms. McShane implies that her use of historical data to estimate the dividend yield is an attempt to reduce measurement error when she states that "the use of an average price lowers the possibility that the estimated cost of equity is attributable to any capital market anomalies that may arise due to transitory investor behavior." (AmerenCILCO Ex. 12.0E (Revised), p. 37; AmerenCILCO Ex. 12.0G (Revised), p. 38) However, while it is true that measurement error is a problem inherent in cost of common equity analysis and should be reduced whenever possible, introducing old stock prices into an analysis simply substitutes one alleged source of measurement error, volatile stock prices, for another, irrelevant stock prices. Stock prices can be influenced by temporary imbalances in supply and demand; however, any distortions such imbalances might have on the measured cost of common equity can be reduced through the use of samples, a technique which Ms. McShane already applies.

Next, consider Ms. McShane's equity risk premium analysis, which calls for an estimate of the investor-required rate of return on the market portfolio. To compute the

[34] Ms. McShane used the average of daily closing stock prices for the period February 26 to March 26, 2009. (AmerenCILCO Ex. 12.0E.4, 12.0E.5 and 12E.6; AmerenCILCO Ex. 12.0G.4, 12.0G.5 and 12G.6)

achieved equity risk premium for her sample, she first calculated the achieved equity risk premium for the S&P 500 Common Stock Index for two historic periods (1926-2008 and 1947-2008) relative to the 20-year U.S. Treasury bond income return.[35] Next, she calculated the achieved equity risk premium for the S&P/Moody's Electric Utility Index and the S&P/Moody's Gas Distribution Utility Index relative to the 20-year U.S. Treasury bond income return.[36] She also estimated the historic equity risk premium relative to the total return on Moody's long-term A-rated public utility bonds.[37] To compute the DCF-based equity risk premium for her Gas sample, Ms. McShane used the period from August 2007 to March 2009.[38]

Consequently, Ms. McShane estimates the required rate of return on the market using, in part, historical earned rates of return. As proxies for current required rates of return, historical earned returns possess several shortcomings. First, the returns an investment generates are unlikely to have equaled investor return requirements due to unpredictable economic, industry-related, or company-specific events. Second, even if an investment's return equaled investor requirements in a given period, both the price of, and the investment's sensitivity to, each source of risk changes over time. Consequently, the past relationship between two investments, such as common equity and debt, is unlikely to remain constant. Third, the magnitude of the historical risk premium depends upon the measurement period used. Unfortunately, no proven method exists for determining the appropriate measurement period. Thus, historical

[35] AmerenCILCO Ex.12.0E (Revised), pp. 48-50 and AmerenCILCO Ex.12.0E.7.1; AmerenCILCO Ex.12.0G (Revised), pp. 51-52 and AmerenCILCO Ex.12.0G.7.1.
[36] AmerenCILCO Ex.12.0E (Revised), pp. 53-54 and AmerenCILCO Ex.12.0E.7.1; AmerenCILCO Ex.12.0G (Revised), pp. 55-56 and AmerenCILCO Ex.12.0G.7.1.
[37] AmerenCILCO Ex.12.0E (Revised), pp. 54-55 and AmerenCILCO Ex.12.0E.7.2; AmerenCILCO Ex.12.0G (Revised), pp. 56-57 and AmerenCILCO Ex.12.0G.7.2.
[38] AmerenCILCO Ex.12.0E (Revised), pp. 55-58 and AmerenCILCO Ex.12.0E.8; AmerenCILCO Ex.12.0G (Revised), pp. 56-57 and AmerenCILCO Ex.12.0G.8.

earned rates of return are questionable estimates of the required rate of return that are susceptible to manipulation and whose use could distort the estimate of a company's cost of common equity.

The Commission rejected use of historical dividend yields in the Docket No. 03-0403 Order (Aqua, then CIWC, rate proceeding), which states:

> The Commission is aware that historical data has a place in many cost of capital analyses. The instant objective, however, is to estimate the forward-looking cost of common equity. For this reason, the Commission has consistently rejected the use of average common stock prices, and has accepted the use of spot common stock prices when implementing the DCF model. The Commission continues to believe that the use of spot common stock prices in the DCF model is superior to the use of average prices.[39]

In addition, the Commission rejected Ms. McShane's use of historical data in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), a previous rate proceeding for the Companies.[40] Referring to Ms. McShane's estimate of the market risk premium, the Commission stated:

> The Commission observes that earned returns on equity are different than expected returns on equity and that the former can not be used to estimate the latter. Additionally, the Commission believes that it would be all too easy to select a historical period that produces a biased result, whether upwardly biased or downwardly biased. As it has done in numerous previous rate cases, the Commission rejects this type of approach to estimating the forward looking cost of common equity. [41]

The Commission should once again reject Ms. McShane's use of historical data in her cost of equity analysis in this proceeding.

[39] Order, Docket No. 03-0403, April 13, 2004, p. 42.

[40] In the Companies' last rate proceeding, Docket Nos. 07-0585 - 07-0590 (Cons.), Ameren accepted Staff's cost of common equity recommendation in its Initial Brief. Hence, the Commission did not address Ms. McShane's analysis in the Final Order. (Order, Docket Nos. 07-0585 - 07-0590 (Cons.), Sept. 24, 2008, p. 180)

[41] Order, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), November 21, 2006, pp. 142-43.

Market to Book Adjustment

Ms. McShane argues that if the market value differs from book value, a cost of equity estimate derived from market values needs to be adjusted when applied to book values of common equity to determine utility rates. She states "when the market value common equity ratio is higher (lower) than the book value common equity ratio, the market is attributing less (more) financial risk to the firm than is 'on the books' as measured by the book value capital structure. Higher financial risk leads to a higher cost of common equity, all other things equal." (AmerenCILCO Ex. 12.0E (Revised), pp. 59-60 and AmerenCILCO Ex. 12.0G (Revised), pp. 61-62) Ms. McShane claims that an adjustment is warranted for her DCF and risk premium derived cost of equity estimates in the instant docket because: 1) both methodologies produce market-based cost of equity estimates; 2) the Commission applies its cost of equity estimate to book value rate base; and 3) application of the market-derived cost of equity for a sample with an average 51% (electric) or 60% (gas) market value common equity ratio to CILCO's 43.6%, CIPS' 48.7%, or IP's 44.1% book value common equity ratio would fail to recognize the higher financial risk of the latter.[42] Hence, she argues that the estimated cost of equity for the comparable utilities needs to be increased when applied to the Company's book value common equity ratio to recognize the higher financial risk of the Company's common book equity.

Market to book adjustments such as Ms. McShane's are based on the flawed argument that a market-derived required rate of return does not produce a "fair" return when applied to a book value rate base if the market to book ratio differs from one. The

[42] AmerenCILCO Ex. 12.0E (Revised), p. 65; AmerenCILCO Ex. 12.0G (Revised), p. 67; AmerenCIPS Ex. 12.0E (Revised), pp. 65-66; AmerenCIPS Ex. 12.0G (Revised), p. 67; AmerenIP Ex. 12.0E (Revised), p. 65; AmerenIP Ex. 12.0G (Revised), p. 67.

crucial flaw in that argument is that it equates secondary investing (i.e., the purchase of existing shares of stock from other investors) with primary investing (i.e., the purchase of new shares of stock directly from the company or the retention of earnings for reinvestment). The former does not affect the amount of money available to the company to buy assets because the proceeds from the sale go to the previous stockholder, not to the company. Thus, a rise in the price of existing common stock traded in secondary markets does not increase the amount of capital actually serving customers. It only reveals that investors' expectations for the future cash flows of the company have risen or that their required rate of return has fallen. In contrast, primary investment directly contributes capital to the company that is available to buy assets to serve customers. Under original cost ratemaking, ratepayers provide a return only on the amount of capital that is invested in assets that serve ratepayers. Inflating that return to compensate investors for capital not invested in plant and equipment is neither fair nor appropriate; moreover, such an adjustment would render the establishment of original cost rate base a pointless exercise.

Book value represents the funds a company receives from investors though security issuances on the primary market (i.e., transactions directly between a company and its investors). Book value does not adjust to reflect changing investor assessments; it only reveals how much money the company has to invest in assets to serve its customers.

In contrast, the market price is the price investors are willing to pay each other for a security on the secondary market. That is, market prices are set by transactions between investors rather than transactions between the company and its investors; therefore, the market value of a company's securities has no bearing on the amount of funding the company has to invest in assets. Cost of common equity analysis uses market price data because market data continuously adjusts to reflect investor return requirements as they are continuously re-evaluated.

The market value of a stock would grow to exceed its book value only if investors expected to earn a return above their required return.[43] If that is the case, the market price will adjust upward until the expected return once again matches the required return. Thus, the market price always reflects the investor required return, regardless of the book value. That is why it is appropriate, indeed necessary, to use a market-based cost of common equity for regulatory rate setting. Similarly, book value always represents the funds available to the company to invest in assets serving its customers, regardless of the market value. That is why it is also appropriate and necessary to use a book value rate base for regulatory rate setting. The application of the market return to the book value simply takes the return investors demand to earn from a dollar invested in the common equity of a company, given the amount of risk in the common equity of that company and the current price of risk, and applies it to the number of common equity dollars invested in the rate base of the Company. Hence, there is no merit to Ms. McShane's claim that her adjustment is required to recognize the higher return that equity investors require for bearing the higher financial risk inherent in the AIU's proposed ratemaking capital structure in comparison to the market value capital structures of the Gas and Electric samples. (Ameren Ex. 36.0, p. 49)

[43] Obviously, neither an expectation of higher than required earnings nor a reduction to the required rate of return justifies a higher authorized rate of return.

If a utility's services were entirely subject to original cost-based, rate of return regulation[44] and its rates perfectly and instantaneously reflected changes in its costs, then the market value of the firm would equal the book value whenever the expected rate of return matches the investor required rate of return. However, if the expected rate of return exceeds the investor required rate of return, then demand for the company's stock will increase as investors seek a share in those abnormally high returns. This increased demand for the company's stock will cause the stock's market value to rise until the expected rate of return on market value equals the required rate of return. Such a scenario would explain why market values of utilities have grown to exceed their book values. Utilities frequently have other sources of cash flows in addition to the operating income component of the revenue requirement set by the Commission. For example, many utility companies own non-regulated assets that generate cash flows for investors. Also, investment tax credits, deferred taxes, and positive working capital balances contribute to utilities' cash flows. Thus, some utilities may be able to earn more than their ratemaking operating income, which, as explained above, would drive the market values of utilities above their book values. Clearly, the Commission should not further increase allowed rates of return when the benefits that utilities receive from other sources of earnings not recognized by the rate setting process increase stock prices above book value. To do so would compensate utilities twice for the same sources of cash flow.

Finally, allowing upward adjustments to the allowed rate of return based on a market to book value ratio greater than one, when taken to its logical conclusion, would

[44] For the purpose of this discussion, the phrase "entirely subject to original cost-based, rate of return regulation" means that a utility's revenues perfectly match its costs including taxes and cost of capital.

require the Commission to continually make upward adjustments to the allowed rate of return, since such an upward adjustment would tend to again increase the market to book value ratio, thereby warranting another increase, resulting in a never ending upward movement in the allowed rate of return. To establish utility rates, regulators generally apply a market-based rate of return to a book value rate base. If that process provided a return that did not meet investor requirements, market prices would fall towards book value. Yet, the market prices of utility stocks continue to exceed book value.

Ms. McShane argues that the lower book value common equity ratios of the Companies relative to the Gas and Electric sample's market value common equity ratios indicate that the Companies possess higher financial risk than the Gas and Electric samples. The intrinsic financial risk of a given company does not change simply because the manner in which it is measured has changed. Such an assertion is akin to claiming that the ambient temperature changes when the measurement scale is switched from Fahrenheit to Celsius. Specifically, capital structure ratios are merely indicators of financial risk; they are not sources of financial risk. Financial risk arises from contractually required debt service payments; changing capital structure ratios from a market to book value basis does not affect a company's debt service requirements. (Staff Ex. 6.0, p. 57)

Ms. McShane made the same adjustment to her market-derived cost of equity estimates in Docket Nos. 02-0798/03-0008/03-0009 (Cons.). The Commission Order rejected her proposed market-to book adjustment stating:

> [T]he Commission has a long history of applying its estimated market required rate of return on common equity to its book value, net original cost rate base for Illinois jurisdictional utilities…. There is no evidence that

> this practice has ever served as an impediment to a utility's ability to raise capital or maintain its financial integrity.[45]

Further, in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), the Commission once again rejected Ms. McShane's proposed market to book adjustment stating:

> [T]he Commission observes that it has repeatedly rejected arguments in favor of using market-to-book ratios as the basis for establishing cost of common equity. The Commission rejects both of the contradictory arguments that market-to-book ratios should be directly used in establishing CILCO's, CIPS', and IP's cost of common equity in this proceeding.[46]

Both of the market to book adjustments proposed by Ms. McShane in the aforementioned dockets were based on the false argument that an adjustment to a cost of equity estimate derived from market values of equity is necessary when that estimate is to be applied to book values of equity to determine utility rates. Thus, the Commission should disregard Ms. McShane's market to book adjustments once again.

Comparable Earnings Model

Ms. McShane's comparable earnings model uses the average historical earned return on book value of common equity for a proxy group of 81 U.S. industrial companies over the period 1991-2007. (AmerenCILCO Ex. 12.0E (Revised), pp. 68-75; AmerenCILCO Ex. 12.0G (Revised), pp. 71-78) The average achieved return for those 81 companies was 15.9%. She claims that her comparable earnings test indicates that competitive firms of similar risk to her sample of gas utilities may be expected to earn average returns of approximately 15.0% - 16.0%.

The comparable earnings methodology is based on the erroneous assumption that earned or expected returns on book equity are acceptable substitutes for investor-

[45] Order, Docket Nos. 02-0798/03-0008/03-0009 (Cons.), October 22, 2003, p. 87.
[46] Order, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), November 21, 2006, p. 141.

required returns. Investor return requirements are a function of risk and manifested in the market prices of securities. In contrast, Ms. McShane's comparable earnings analysis is based on accounting returns, which are largely unresponsive to market forces. The return on book value of common equity is entirely unaffected by changes in the investor required rate of return. For example, in response to a decline in risk, risk premiums, or the time value of money, investors would bid up the price of a stock, thereby reducing the implied required rate of return, but the anticipated return on book equity would not change. Ms. McShane herself acknowledged that the comparable earnings test does not measure the investor-required rate of return on equity. Hence, the returns being earned by unregulated companies do not provide a relevant perspective on the reasonableness of the recommended return on equity, as Ms. McShane claims. (Ameren Ex. 36.0, pp. 49-51)

The Commission has consistently and repeatedly rejected the comparable earnings methodology. Ms. McShane presented a comparable earnings model in Docket Nos. 02-0798/03-0008/03-0009 (Cons.) and the Commission rejected it, adopting instead the Staff's DCF methodology.[47] Ms. McShane again offered a comparable earnings test as part of her cost of equity analysis in Docket Nos. 06-0070/06-0071/06-0072 (Cons). The Commission rejected the comparable earnings test in that proceeding and stated:

> Among other things, the Commission believes that the comparable earnings test is faulty because it incorrectly assumes the earned returns on book common equity are the same as, or representative of, investor-required returns on common equity.[48]

The Commission also rejected use of the comparable earnings methodology in

[47] Order, Docket Nos. 02-0798/03-0008/03-0009 (Cons.), October 22, 2003, pp. 88-89.
[48] Order, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), November 21, 2006, p. 141-42.

Docket Nos. 03-0676/03-0677 (Cons.), Docket Nos. 01-0528/01-0628/01-0629 (Cons.), Docket Nos. 99-0121, 92-0448/93-0239 (Cons.), and Docket No. 89-0033.[49]

Both of the comparable earnings analysis in the prior cases cited above are based on earned returns on book equity as substitutes for investor required returns. In this proceeding, Ms. McShane claims that the results of the comparable earnings test should be relied on as an indicator of whether her market-based test results (the DCF and equity risk premium), as adjusted for the market/book ratio are reasonable. The Commission should once again disregard Ms. McShane's comparable earnings analysis.

c. Growth Rates

Ameren witness McShane insists that it is appropriate to include the results of the constant growth DCF analysis in the estimation of the investor required rate of return for the AIUs. In Staff's opinion, the 3-5 year growth rates for the companies in the Gas and Electric samples cannot be sustained over the long-term. (Staff Ex. 20.0, pp. 25-26)

Ms. McShane notes that Staff did utilize a constant growth DCF to develop the expected return in the market in the risk premium model. (Ameren Ex. 36.0, pp. 6-7) Staff's use of the constant growth DCF to estimate the return on the market does not support performing a constant growth DCF analysis on the Gas and Electric samples. Staff did not use a non-constant growth DCF to estimate the return on the market because of the extreme difficulty of attempting to apply the more elaborate non-constant

[49] Order, Docket Nos. 03-0676/03-0677 (Cons.), October 6, 2004, p. 40; Order, Docket Nos. 01-528/01-0628/01-0629 (Cons.), March 28, 2002, p. 13; Order, Docket No. 99-0121, August 25, 1999, p. 68); Order, Docket Nos. 92-0448/93-0239 (Cons), October 11, 1994, p. 173; Order on Remand, Docket No. 89-0033, November 4, 1991, p. 15.

growth DCF on 500 companies.[50] As with the 3-5 year growth rates for some of the companies in the Gas and Electric samples, some of the growth rates used in Staff's DCF analysis of the S&P 500 are unsustainably high, which produces an upward bias in Staff's market return estimate and, thus, in Staff's CAPM cost of equity estimate. (Staff Ex. 20.0, p. 26)

While Staff used the implied forward yield on 20-year Treasury bonds to estimate long-term overall economic growth during the steady state growth stage of the non-constant DCF analysis, Ms. McShane advocates using the Blue Chip forecast to estimate long-term economic growth. (Ameren Ex. 36.0, p.5) The Blue Chip forecast used by Ms. McShane to estimate long-term economic growth only projects forward ten years. The period for which the long-term growth rate is applied begins after ten years. Hence, the forecasts on which she relies do not even overlap, much less coincide with, the period of time the steady-state growth stage covers. Nevertheless, Ms. Freetly did compare her 4.83% U.S. Treasury yield-based estimate of the long-term growth rate to Global Insight's 4.5% forecast for nominal GDP growth for the 2019 to 2039 period. (Staff Ex. 6.0, p. 8) Thus, Ms. Freetly's estimate of the long-term growth in the economy ten years from now is similar to that of a professional forecast service. (Staff Ex. 20.0, p. 26)

Ms. McShane points to the recent swings in the implied 20-year forward Treasury yield in comparison to the virtually unchanged consensus forecasts of long-term economic growth. The changes in the Treasury yield indicate that investor's current

[50] Mr. Gorman's non-constant DCF analysis of the S&P500 illustrates the difficulty of applying that model to the diverse group of companies that compose that index. Using a two stage model with a ten-year first stage, Mr. Gorman estimated the required rate of return on the market equals 8.71%. This estimate is 129 percentage points below the 10.00% rate of return on common equity Mr. Gorman recommends for the AIU. (IIEC Ex. 2.0, pp. 49 and 51) These two cost of common equity estimates imply that the S&P 500 is less risky than the AIU, which is not plausible.

long-term expectations vary over time. In contrast, Ms. McShane's argument implies that investors' expectations of the long-term economic growth are essentially static. Since the yield on Treasury bonds reflects changing investor expectations due to current economic conditions, it is a timely gauge of the expected long-term economic growth. In contrast, the long-term forecasts that Ms. McShane relies on might not be updated very often. For example, EIA updates its long-term forecast annually; Global Insight updates its long-term forecast semi-annually, and Federal Reserve Bank of Philadelphia updates its *Survey of Economic Forecasters* projection of real GDP growth annually. Hence, the alleged stability in the Blue Chip forecasts of long-term economic growth might come from a low update frequency. (*Id.*, p. 27)

d. Beta

Ms. McShane criticized Staff's regression betas for being consistently lower than Value Line betas. (Ameren Ex. 36.0, p. 9) The observation that regression betas have been consistently lower than Value Line betas does not provide insight into which beta estimation procedure is superior.[51] The Value Line methodology is not inherently superior to Staff's methodology. Value Line, Zacks and regression betas are <u>estimates</u> of the unobservable true beta, which measures investors' expectations of the quantity of non-diversifiable risk inherent in a security. Consequently, which beta estimates are more accurate is unknown. Different beta estimation methodologies can produce different betas when those methodologies employ different samples of stock return data. The methodology Staff used to calculate the regression betas for the Gas sample,

[51] The Companies' customers could be concerned that the Value Line weekly betas have been consistently higher than monthly betas.

which Staff has regularly used and the Commission has consistently approved,[52] employs the same monthly frequency of stock price data as the widely accepted Merrill Lynch methodology. Further, Ms. McShane's argument to exclude Staff calculated betas and rely upon only Value Line betas was rejected by the Commission in Docket No. 00-0340.[53] (Staff Ex. 20.0, pp. 27-28)

Ms. McShane presented an analysis comparing weekly and monthly betas to support her conclusion that weekly betas are to be preferred. Ms. McShane's analysis is misleading. The statistics that she presents do not compare the "superiority" of the parameter estimates (i.e., beta) that result from the different samplings used to estimate the same model. They test the predictive ability of the model. That is, the data samples are being used to test the ability of market stock returns to predict Gas sample stock returns. The t-statistic measures the extent to which an estimate differs from zero; hence, the higher the beta, the higher the t-statistic. The adjusted R^2 measures the percent of variation of the stock return explained by the variation of the market return; hence, the higher the beta, the higher the adjusted R^2. Both of these statistics are a function of how high the beta estimate is and do not indicate which beta estimates are more accurate.

To illustrate the relationship between the t-statistic and adjusted R^2 and the beta, or the dependent variable, in regression analysis, Staff conducted regression analyses on two simulated data sets of 64 observations with a normally distributed random error term. For the first data set, Staff assumed the dependent variable, y, was equal to half of the independent variable plus the random error ($y = 0.5x + e$). Thus, in the first

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[52] *See, e.g.,* Order, Docket No. 02-0837, October 17, 2003, pp. 37-38; Order, Docket Nos. 02-0798/03-0008/03-0009 (Cons.), October 22, 2003, p. 85; Order, Docket No. 00-0340, February 15, 2001, p. 25; and Order, Docket No. 03-0403, April 13, 2004, p. 42.

[53] Order, Docket No. 00-0340, February 15, 2001, p. 25.

regression, beta equals 0.5. For the second regression, Staff assumed y = x + e, using the same random error sequence. Thus, in the second regression, beta equals one. Despite the identical error values, the t-statistic and R^2 were both higher in the second regression when the parameter estimate, x, was higher.[54] (*Id.*, pp. 30-31)

To test the predictive accuracy of different betas, the beta estimate has to be the independent variable. In Ms. McShane's analysis, beta is the parameter estimate. Her test simply indicates how much the variation in the market return explains the variation in the return of the stock. Her analysis does not support her conclusion that monthly betas are statistically inferior to weekly betas. (*Id.*, p. 31)

Ms. McShane did not provide any academic support for her conclusion that weekly betas are superior to monthly betas. The Companies' response to Staff DR JF 3.02 (Attachment B to Staff Ex. 20.0) provided discussions of the regression statistics used to evaluate beta calculations, but did not compare the weekly versus monthly methodologies. None of the published studies, including those Staff obtained (discussed below), which directly compared the weekly and monthly betas, utilize statistics that Ms. McShane claims demonstrate that weekly betas are superior to monthly betas. In fact, none of the studies conclude that either beta is superior. (*Id.*, p. 32)

In response to Staff DR JF 6.04, the Company stated that Ms. McShane was not aware of any studies that have addressed whether weekly betas are more accurate predictors of future utility stock performance than monthly betas. (*Id.*, pp. 32-33) The response also presented Ms. McShane's position that the weekly adjusted Value Line

[54] In the first regression, the t-statistic and R^2 equaled 17.62 and 0.83, respectively. In the second regression, the t-statistic and R^2 equaled 35.52 and 0.95, respectively.

betas underestimated actual returns over the 1947-2008 time periods. She computed an implied beta for gas distributors by dividing the achieved gas utility risk premium by the achieved risk premium for the S&P 500 for the periods 1992-2008 and 1947-2008. The major problem with her analysis is that it assumes that risk did not change throughout the 1992-2008 and 1947-2008 time periods. As companies change over time, their level of systematic risk can change as well. However, changes in risk can bias the beta estimate. A *decrease* in a company's systematic risk can *increase* its estimated beta even though generally an increasing beta would be interpreted as signaling an *increase* in a company's systematic risk. Conversely, an *increase* in a company's systematic risk can actually *lower* its calculated beta even though generally a decreasing beta would be interpreted as signaling a *decrease* in a company's systematic risk.[55] Those counter-intuitive results are a consequence of the inverse relationship between risk and stock values. As the risk of a stock declines, its price rises, all else equal. As that stock price rises, its calculated beta rises, all else equal. Consequently, given the long time period examined, one cannot conclude that the Value Line betas underestimate actual returns and using monthly returns would have further underestimated the actual returns for gas distributors from those implied betas because the relatively high gas group returns could be a consequence of declining systematic risk. (*Id.*)

As stated previously, Ms. McShane could cite no studies comparing weekly and monthly betas. In contrast, Staff cited two studies that compared weekly and monthly beta estimates but neither concluded that either beta was superior. (*Id.*, p. 28) Those

[55] Brigham, Eugene F. and Crum, Roy L., *On the Use of the CAPM in Public Utility Rate Cases*, Financial Management, Summer 1977, pp. 7-15.

studies found a relatively weak relationship between Value Line and Merrill Lynch betas and showed that the major cause of the significant differences in beta was the use of monthly versus weekly return intervals. Time interval differences do not necessarily mean one beta estimate is statistically superior to another beta estimate. The difference in beta estimates may be the effect of non-synchronous trading, which occurs when the market return reflects information that is not yet reflected in the stock's return. The problem of non-synchronous trading increases as the time interval decreases.

Staff investigated whether non-synchronous trading was a problem for weekly or monthly betas. To account for the lag in stock price reaction to economic events that affect the market, security returns can be regressed against the returns of the market in the current period as well as the returns of the market in prior periods. The coefficients for the current and lagged regressions are then summed together to derive a beta estimate.[56] Staff calculated Ms. McShane's weekly regression betas with three lags, with the security returns of the Gas sample lagging behind the market data by one, two and three weeks. The one and two week lags, which are -0.07 and -0.11, respectively, are statistically different from zero, which indicates that non-synchronous trading is a problem with Ms. McShane's weekly data.[57] Staff also calculated the lag beta for the monthly regression beta for the Gas sample that Staff proposed. The lag beta was not significantly different from zero, which indicates that non-synchronous trading was not a problem when using monthly data.[58] The longer time interval thereby diminished the effect of non-synchronous data. (*Id.*, pp. 29-30)

[56] Hereafter, the beta for a lagged market return will be referred to as a "lag beta."

[57] The one-week lag beta is significantly different than zero at the .10 level. The two-week lag beta is significantly different than zero at the .01 level.

[58] Because I was unable to verify much of Ms. McShane's monthly data, I performed the non-synchronous trading analysis on Staff's monthly return data set.

Ms. McShane speculated that the results might relate to the market conditions during the financial crisis since the same analysis conducted for the periods ending 2005 and 2006 produces different results. (Ameren Ex. 52.0, p. 13) Ms. McShane's speculation is irrelevant. Staff's lag beta analysis used the same five year time period as Ms. Freetly's CAPM analysis to estimate the investor-required rate of return. Hence, it is the relevant time period to examine to determine whether non-synchronous trading affected the data Ms. Freetly used to calculate beta.

Further, Staff compared the coefficient of variation using Ms. McShane's weekly and monthly data, which is a measure of the relative variation.[59] The coefficient of variation was higher for weekly data. Although the higher number of observations of the weekly data increases the degrees of freedom, and hence narrows confidence intervals, it also increases the magnitude of the variation relative to the mean of the sample stock returns, which leads to an increase in random error. (Staff Ex. 20.0, pp. 31-32)

In conclusion, weekly and monthly betas have strengths and weaknesses relative to each other. As Ms. McShane's analysis shows, the standard error of weekly beta estimates is generally lower than those for monthly beta estimates. This lower standard error indicates that weekly betas are usually more reliable (i.e., have lower variation in the beta estimate) than monthly betas. Conversely, monthly betas are less susceptible to non-synchronous trading than weekly betas. Further, monthly betas are calculated from returns that have lower coefficients of variation (i.e., lower volatility per mean return) than weekly betas. The lower coefficients of variation indicate that the monthly betas are more accurate than weekly betas. Since neither type of beta is clearly

[59] The coefficient of variation is the ratio of the standard deviation of the sample stock returns to the average of the sample stock returns.

superior to the other, Staff recommends the Commission equally weight weekly and monthly betas in determining a cost of common equity with the CAPM. (*Id.*, pp. 33-34)

e. Market Risk Premium

Risk-free Rate

Ms. McShane states that a "spot" yield should not be relied upon as representative of expected yields and used as the risk-free rate in the CAPM. (Ameren Ex. 36.0, p. 12) The current U.S. Treasury yields that Staff used to estimate the risk-free rate reflect all relevant, currently available information, including investor expectations regarding future interest rates. Consequently, investor appraisals of the value of forecasts are also reflected in current interest rates. Therefore, if investors believe that the forecasts are valuable, that belief would be reflected in current market interest rates. Interest rates are constantly adjusting and accurately forecasting the movements of interest rates is problematic. Thus, the Commission should continue to rely on current, observable interest rates rather that the forecasted rates supported by Ms. McShane. (Staff Ex. 20.0, p. 34)

f. Proposed Adjustments

(1) Financial Risk

Based on a simple average of her DCF and risk premium analyses, Ms. Freetly estimated that the investor-required rate of return on common equity is 9.63% for the Gas sample (Staff Ex. 6.0, p. 24) and 10.44% for the Electric sample (Staff Ex. 20.0, p. 2). The Gas sample serves as a proxy for the natural gas distribution operations of the target companies, CILCO, CIPS and IP, and the Electric sample serves as a proxy for the electric operations and should therefore reflect the risks of the Companies. If the proxy does not accurately reflect the risk level of the target company, an adjustment should be made. Since the operating risks of the Gas and Electric samples are similar to the gas and electric operations of the Companies, a review of the relative financial risks of the Gas and Electric samples is required.

To estimate the financial risk of the Companies going forward, Ms. Freetly compared the financial strength implicit in Staff's proposed revenue requirement for each company's gas and electric operations to Moody's guidelines for the regulated gas and electric utilities. Although no formula exists for determining an assigned credit rating, Moody's provides broad guidelines on the ratio ranges that may generally be seen at different rating levels for regulated gas and electric utilities. To assess the financial strength of gas and electric utilities, Moody's focuses on four ratios: (1) funds from operations ("FFO") to interest coverage; (2) FFO to total debt; (3) retained cash flow ("RCF") to total debt coverage; and (4) debt to capitalization.[60,61]

The updated Moody's guidelines for regulated gas and electric utilities, along with the AIUs gas utilities' scores on those financial ratios are listed below in Table 1 – Moody's Guideline Ratios for Gas Utilities. In summary, Ms. Freetly concluded that Staff's revenue requirement recommendations, including Staff's cost of common equity recommendations, indicate levels of financial strength that are commensurate with a Baa3 credit rating for CILCO Gas, an A3 credit rating for CIPS Gas and a Baa3 credit rating for IP Gas. (*Id.*, pp. 3-5)

[60] Moody's Investors Service, *Rating Methodology: Regulated Electric and Gas Utilities*, August 2009, p. 8.
[61] The financial ratios are calculated as described in Ms. Freetly's Direct testimony – Staff Ex. 6.0, p. 36, ll. 657-667 and Schedule 6.08.

Table 1 – Moody's Guideline Ratios for Gas Utilities

	Aaa	Aa	A	Baa	Ba
Financial Guideline Ratios					
FFO/IC	> 8.0x	6.0-8.0x	4.5-6.0x	2.7-4.5x	1.5-2.7x
FFO/Debt	> 40%	30-40%	22-30%	13-22%	5-13%
RCF/Debt	> 35%	25-35%	17-25%	9-17%	0-9%
Debt/Capitalization	< 25%	25-35%	35-45%	45-55%	55-65%
Gas Sample					
FFOIC			4.98x		
FFO/Debt				21.48%	
RCF/Debt				15.31%	
Debt/Capitalization				53.37%	
Staff Proposal – CILCO G					
FFOIC				3.17x	
FFO/Debt				13.53%	
RCF/Debt				13.25%	
Debt/Capitalization				53.09%	
Staff Proposal – CIPS G					
FFOIC			4.96x		
FFO/Debt			23.20%		
RCF/Debt			22.65%		
Debt/Capitalization				46.35%	
Staff Proposal – IP G					
FFOIC				3. 23x	
FFO/Debt				17.36%	
RCF/Debt				13.26%	
Debt/Capitalization				54.56%	

In contrast, the Gas sample's average financial ratios for 2006-2008 are indicative of a level of financial strength that is commensurate with a credit rating of Baa1, which is consistent with the current average credit ratings Moody's has assigned the Gas sample. (*Id.*, p. 5) The Gas sample's level of financial strength indicates that it has more financial risk than the natural gas distribution operations of CIPS and less financial risk than the natural gas distribution operations of CILCO and IP. Financial theory posits that investors require higher returns to accept greater exposure to risk. Conversely, the investor-required rate of return is lower for investments with less exposure to risk. Thus, given the difference between the credit rating commensurate with the forward-looking financial strength of the Companies' gas distribution operations and the credit rating commensurate with the financial strength of the Gas sample, the sample's average cost of common equity needs to be adjusted to determine the final estimate of the Company's cost of common equity. (*Id.*; Staff Ex. 6.0, pp. 25-26)

Using 30-year utility debt yield spreads published by Reuters, Ms. Freetly calculated the yield spreads between the credit ratings implied by the financial ratios for the Companies and those of the Gas sample. The spread between the implied ratings of A3 for CIPS and Baa1 for the Gas sample is 50 basis points. The spread between the implied ratings of Baa3 for CILCO and IP and Baa1 for the Gas sample is 35 basis points. To determine the cost of equity adjustment, Ms. Freetly then multiplied those yield spreads by 30%, which is the percent of the overall credit rating that Moody's assigns to the financial ratios under the new rating methodology for regulated gas and electric utilities. Thus, Staff's financial risk adjustment to the cost of equity for the gas operations is an increase of 10.5 basis points for CILCO and IP and a decrease of 15 basis points for CIPS. (*Id.*, pp. 27-28)

The updated Moody's financial guideline ratios for electric utilities, along with the AIUs electric utilities' scores on those financial ratios are listed below in Table 2 – Moody's Guideline Ratios for Electric Utilities. In summary, Ms. Freetly concludes that Staff's revenue requirement recommendations, including Staff's cost of equity recommendations, indicate a level of financial strength that is commensurate with a Baa1 credit rating for CILCO, an Aa3 credit rating for CIPS, and a Baa2 credit rating for IP. (Staff Ex. 20.0, pp. 7-9)

Table 2 – Moody's Guideline Ratios for Electric Utilities

	Aaa	Aa	A	Baa	Ba
Financial Guideline Ratios					
FFO/IC	> 8.0x	6.0-8.0x	4.5-6.0x	2.7-4.5x	1.5-2.7x
FFO/Debt	> 40%	30-40%	22-30%	13-22%	5-13%
RCF/Debt	> 35%	25-35%	17-25%	9-17%	0-9%
Debt/Capitalization	< 25%	25-35%	35-45%	45-55%	55-65%
Electric Sample					
FFOIC				4.1x	
FFO/Debt				20.3%	
RCF/Debt				14.95%	
Debt/Capitalization				54.82%	
Staff Proposal – CILCO E					
FFOIC				4.37x	
FFO/Debt				21.04%	
RCF/Debt			20.76%		
Debt/Capitalization				53.09%	
Staff Proposal – CIPS E					
FFOIC		7.04x			
FFO/Debt		35.38%			
RCF/Debt		34.83%			
Debt/Capitalization				46.35%	
Staff Proposal – IP E					
FFOIC				3.60x	
FFO/Debt				20.24%	
RCF/Debt				15.82%	
Debt/Capitalization				54.56%	

In contrast, the Electric sample's average financial ratios for 2006-2008 are indicative of a level of financial strength that is commensurate with a credit rating of Baa2, which is consistent with the current average credit ratings Moody's has assigned the Electric sample. (*Id.*, p. 9) The Electric sample's level of financial strength indicates that it has more financial risk than the electric delivery service operations of CILCO and CIPS. Thus, given the difference between the credit rating commensurate with the forward-looking financial strength of the Companies' electric delivery service operations and the credit rating commensurate with the financial strength of the Electric sample, the sample's average cost of common equity needs to be adjusted to determine the final estimate of the Companies' cost of common equity. (*Id.*, pp. 9-10)

Using 30-year utility debt yield spreads published by Reuters, Ms. Freetly calculated the yield spreads between the credit ratings implied by the financial ratios for the Companies and those of the Electric sample. The spread between the implied ratings of Baa1 for CILCO and Baa2 for the Electric sample is 20 basis points. The spread between the implied ratings of Aa3 for CIPS and Baa2 for the Electric sample is 100 basis points. To determine the cost of equity adjustment, Ms. Freetly then multiplied those yield spreads by 30%, which is the percent of the overall credit rating that Moody's assigns to the financial ratios under the new rating methodology for regulated gas and electric utilities. Thus, Staff's financial risk adjustment to the cost of equity for the electric operations is a decrease of 6 basis points for CILCO and 30 basis points for CIPS. (*Id.*, pp. 10-11)

(2) Fixed Customer Charge

The Commission authorized the AIU gas utilities to recover 80% of the fixed delivery service costs through the monthly customer charge in the last rate cases. This cost recovery method will remain in effect when the rates set in this proceeding go into effect. In the AIU's last rate cases, the Commission recognized that this move toward more fixed cost recovery through the fixed monthly charge provides the AIU gas utilities more assurance of recovering its fixed costs of service for gas operations. Hence, this cost recovery reduces risk and provides the utilities greater assurance that the authorized rate of return will be earned. Therefore, a downward adjustment to the AIU gas utilities' rate of return on common equity is appropriate to reflect this reduction in risk. As discussed in Ms. Freetly's direct testimony, her cost of common equity recommendation includes the same 10 basis point adjustment to the cost of common equity for the AIU gas companies that the Commission found appropriate in the last rate cases to reflect the reduction in risk provided by this method of cost recovery. (Staff Ex. 6.0, pp. 32-33)

Ms. McShane claims that eight of the nine gas distributors in the Gas sample have similar mechanisms in place and therefore, the cost of common equity estimate for the Gas sample already reflects the risk reduction. (Ameren Ex. 36.0, pp. 16-17) While most of the companies in the Gas sample have in place some sort of de-coupling mechanism, some of those mechanisms are only applicable to a portion of the company's service territories, and one of the companies has no de-coupling mechanism at all. Thus, a small cost of equity adjustment for the reduction in risk provided by this method of cost recovery is clearly warranted, and the 10 basis point downward adjustment adopted in the Companies' last rate case is appropriate in this proceeding. (Staff Ex. 20.0, p. 7)

(3) Uncollectibles Riders

Although Staff's cost of equity recommendations do not take into account any change in risk associated with the new uncollectibles riders the Companies are proposing in Docket No. 09-0399, Staff recommends further adjustment to the cost of common equity for the uncollectibles riders when authorized by the Commission. (Staff Ex. 6.0, p. 37) Pursuant to Illinois Public Act 96-0033, the AIUs filed a petition for approval of uncollectible riders on August 31, 2009 in Docket No. 09-0399. The proposed riders would be applicable to both gas ("Rider GUA" – Gas Uncollectible Adjustment) and electric ("Rider EUA" – Electric Uncollectible Adjustment) customers.

According to the direct testimony of Ameren witness Robert J. Mill in Docket No. 09-0399, the purpose of these riders is to allow the Companies to recover actual uncollectibles amounts through an automatic adjustment clause, which are not otherwise recovered through base delivery service charges or via supply charges. Specifically, he states "Section 16-111.8a of the law states that the uncollectible recovery for a utility is based on '…the incremental difference between its actual uncollectible amount as set forth in Account 904 in the utility's most recent annual FERC Form 1 and the uncollectible amount included in the utility's rates for the period reported in such annual FERC Form 1.'"[62] (*Id.*, pp. 37-38)

The uncollectibles riders authorized by Public Act 96-0033 would ensure more timely and certain collection of bad debt expense. This cost recovery mechanism provides greater assurance that the Companies will earn their authorized rates of return. Since the uncollectible riders would reduce uncertainty of cash flows, it would reduce the Companies' risk. Therefore, downward adjustments to the Companies' rates of return on common equity would be appropriate to recognize the reduction in risk associated with the use of the uncollectibles riders when authorized by the Commission. (*Id.*, p. 38)

Moody's Investors Service recently upgraded the ratings of the AIUs to investment grade.[63] The upgrade reflects positive developments in Illinois, including the recently passed legislation providing Illinois utilities with a bad debt rider. Moody's acknowledges that such riders would reduce the risk of the utilities by providing greater

[62] Docket No. 09-0399, Ameren Exhibit 1.0, Direct Testimony of Robert J. Mill, p. 3. (filed August 31, 2009)

[63] Moody's Investors Service, Rating Action: *Moody's Upgrades Ameren Illinois Utilities to Investment Grade*, August 13, 2009.

assurance of bad debt cost recovery and factored that into the decision to upgrade the AIUs to investment grade. (*Id.*, p. 39)

Staff is unaware of any established approach for precisely gauging the effect the adoption of the uncollectibles riders would have on investors' perceptions of the Companies' risk levels and the resulting costs of equity. Thus, any adjustment will inevitably be inexact. Therefore, Staff's proposed adjustments for Riders GUA and EUA reflect a range of alternatives using two distinct approaches. (*Id.*, p. 39)

In the first approach, Staff estimated the effect the adoption of Riders GUA and EUA would have on the Companies' Moody's credit ratings and based the adjustment of the resulting change in the implied yield spreads. Moody's updated rating methodology for regulated electric and gas utilities focuses on four core rating factors: regulatory framework, ability to recover costs and earn returns, diversification, and financial strength and liquidity.[64] These four factors are measured, assigned to a Moody's rating category and weighted before being translated into the overall rating, as described in Ms. Freetly's direct testimony. (*Id.*, pp. 39-40)

Of the four updated rating factors, the adoption of an uncollectibles rider would affect the utilities' ability to recover costs and earn returns. This rating factor assesses the ability of the utility to recover prudently incurred costs in a timely manner. For local gas distribution companies in the United States, this factor addresses the sustainable profitability and regulatory support assessments in the previous methodology.[65] A utility's score on this factor would improve with implementation of an uncollectibles rider that allows timely adjustment of rates to cover uncollectible costs since its ability to earn

[64] Moody's Investors Service, *Rating Methodology: Regulated Electric and Gas Utilities*, August 2009.

[65] Moody's Investors Service, *Rating Methodology: Regulated Electric and Gas Utilities*, August 2009, p. 8.

its authorized rate of return would be enhanced. Moody's assigns a 25% weight to this factor when determining the overall credit rating score. (Staff Ex. 20.0, p. 15)

Staff assumed that the credit rating assigned to this factor would improve by one credit rating (i.e., 3 points on the numeric scale) with the implementation of the uncollectibles rider. Since this factor comprises 25% of the overall weighting, raising the score for this factor by 3 rating points, as described above, would result in an improvement to the Companies' overall credit ratings of approximately one credit rating notch (i.e., 3 x 25% = 0.75). For example, if the rating for a company is Baa1 before the rider, then the same company would likely improve to A3 after the rider.

For the natural gas distribution operations, Staff's analysis indicates that the going forward level of financial strength is consistent with credit ratings of Baa3 for CILCO and IP and A3 for CIPS. This analysis indicates that the ratings would go up to Baa2 for CILCO and IP and A2 for CIPS due to Rider GUA. Hence, the returns on common equity would be reduced by the 15 basis point spread between credit ratings of Baa3 and Baa2 for CILCO and IP, and by the 10 basis point spread between credit ratings of A3 and A2 for CIPS. (*Id.*, p. 15)

For the electric delivery service operations, Staff's analysis indicates that the going forward level of financial strength is consistent with credit ratings of Baa1 for CILCO, Aa3 for CIPS, and Baa2 for IP. This analysis indicates that the ratings would go up to A3 for CILCO, Aa2 for CIPS, and Baa1 for IP due to Rider EUA. Hence, the returns on common equity would be reduced by the 50 basis point spread between credit ratings of Baa1 and A3 for CILCO, by the 10 basis point spread between credit ratings of Aa3 and Aa2 for CIPS, and by the 20 basis point spread between credit ratings of Baa2 and Baa1 for IP. (*Id.*, p. 16)

The second approach is an iterative process of adjusting Staff's cost of common equity estimate downward to offset the increased operating income resulting from the adoption of Rider GUA as proposed by the Companies in Docket No. 09-0399 (hereafter, "Operating Income Analysis"). Based on Staff's pre-adjustment rate of return recommendations of 9.64% for CILCO Gas and IP Gas and 9.38% for CIPS Gas and Staff's rate base recommendations of $190,360,000 for CILCO Gas, $193,701,000 for CIPS Gas and $511,117,000 for IP Gas, Ms. Freetly calculated pro forma operating incomes without Rider GUA (Staff's rate base x rate of return recommendations) of $15,135,546 for CILCO Gas, $14,884,141 for CIPS Gas and $44,473,038 for IP Gas. To estimate the effect Rider GUA would have on the pro forma operating income of each of the AIU gas utilities, Ms. Freetly subtracted the Companies' estimates of uncollectibles recovery via base rates from the Account 904 balances for the years 1999-2008.[66] She then divided the average difference between the Companies' estimates of uncollectibles recovery via base rates and Account 904 balances over the last ten years by the pro forma operating income without Rider GUA. If Rider GUA had been in effect during the last ten years, Staff's analysis indicates that the pro forma operating incomes for the gas operations of CILCO, CIPS and IP would have been approximately 9.61%, 10.35% and 5.60% higher, on average. Thus, Ms. Freetly multiplied the pro forma operating incomes for the gas operations of CILCO, CIPS and IP by those respective amounts to estimate the effective pro forma operating incomes if Rider GUA were adopted but no adjustments were made. Ms. Freetly then adjusted her cost of common equity downward until the pro forma operating incomes under Rider GUA equaled the original pro forma operating incomes Staff calculated for the

[66] Companies' Responses to Staff DRs JF 2.06 and JF 4.02.

Companies without Rider GUA. This process produced downward adjustments to the costs of equity for the gas operations of CILCO, CIPS and IP of approximately 160, 149 and 106 basis points, respectively, to reflect the risk reduction associated with Rider GUA. (*Id.*, pp. 16-17)

For the electric delivery service operations of the Companies, Staff estimated the incremental recovery of uncollectibles expense had Rider EUA been in effect for the past ten years in the same manner as described on pages 43 through 45 of Janis Freetly's direct testimony. (Staff Ex. 6.0, pp. 43-45; Staff Ex. 20.0, pp. 17-19)

Based on Staff's pre-adjustment rate of return recommendations of 10.38% for CILCO Electric, 10.14% for CIPS Electric and 10.44% for IP Electric, and Staff's rate base recommendations of $309,967,000 for CILCO Electric, $533,616,000 for CIPS Electric and $1,464,727,000 for IP Electric, Ms. Freetly calculated pro forma operating incomes without Rider EUA (Staff's rate base x rate of return recommendations) of $25,652,505 for CILCO Electric, $42,977,311 for CIPS Electric and $132,582,798 for IP Electric.

For CILCO Gas, the ratio of average Account 904 balances to pro forma operating income is 17.93%. For CILCO Electric, the ratio of average Account 904 balances to pro forma operating income is 7.70%. Ms. Freetly then divided the ratio for the electric operations by the ratio for the gas operations (7.70% ÷ 17.93% = 42.94%) and applied 42.94% of the operating income adjustment for the gas operations to the electric operations. Thus, Staff estimates the operating income for CILCO Electric would have been approximately 4.12% (42.94% x 9.61% = 4.12%) higher, on average, if Rider EUA had been in effect during the last ten years.

For CIPS Gas, the ratio of average Account 904 balances to pro forma operating income is 15.94%. The ratio of average Account 904 balances to operating income for the CIPS Electric is 11.91%. The ratio for the electric operations divided by the ratio for the gas operations is 74.71% (11.91% ÷ 15.94% = 74.71%). Thus, Staff estimates the operating income for CIPS Electric would have been approximately 7.73% (74.71% x 10.35% = 7.73%) higher, on average, if Rider EUA had been in effect during the last ten years.

For IP Gas, the ratio of average Account 904 balances to pro forma operating income is 12.49%. The ratio of average Account 904 balances to operating income for the IP Electric is 5.25%. The ratio for the electric operations divided by the ratio for the gas operations is 42.03% (5.25% ÷ 12.49% = 42.03%). Thus, Staff estimates the operating income for IP Electric would have been approximately 2.35% (42.03% x 5.25% = 2.35%) higher, on average, if Rider EUA had been in effect during the last ten years.

Ms. Freetly then multiplied the pro forma operating incomes for the electric operations of CILCO, CIPS and IP by 4.12%, 7.73% and 2.35%, respectively, to estimate the effective pro forma operating incomes if Rider EUA were adopted but no adjustments were made. She then adjusted her cost of common equity downward until the pro forma operating incomes under Rider EUA equaled the original pro forma operating incomes she calculated for the Companies without Rider EUA. This process produced downward adjustments to the costs of common equity for the electric operations of CILCO, CIPS and IP of approximately 76, 119 and 48 basis points, respectively, to reflect the risk reduction associated with Rider EUA.

Table 3 below summarizes the results of the two approaches Staff used to estimate the downward adjustments to the required costs of common equity for the gas operations of CILCO, CIPS and IP necessary to reflect the reduced risk that would result from the adoption of Rider GUA.

Table 3			
Approach	CILCO Gas	CIPS Gas	IP Gas
Implied Moody's ratings adjustment	15 basis points	10 basis points	15 basis points
Operating income adjustment	160 basis points	149 basis points	106 basis points

Those results range from 15 to 160 basis points for CILCO Gas, 10 to 149 basis points for CIPS Gas and 15 to 106 basis points for IP Gas. Based on the midpoints of those ranges, Staff recommends adjustments to the costs of common equity for the gas operations of CILCO, CIPS and IP of 87.5, 79.5 and 60.5 basis points, respectively, to reflect the reduced risk that will result from the adoption of Rider GUA.

Table 4 below summarizes the results of the two approaches Staff used to estimate the downward adjustments to the required costs of common equity for the electric operations of CILCO, CIPS and IP necessary to reflect the reduced risk that would result from the adoption of Rider EUA.

Table 4			
Approach	CILCO Electric	CIPS Electric	IP Electric
Implied Moody's ratings adjustment	50 basis points	10 basis points	20 basis points
Operating income adjustment	76 basis points	119 basis points	48 basis points

Those results range from 50 to 76 basis points for CILCO Electric, 10 to 119 basis points for CIPS Electric and 20 to 48 basis points for IP Electric. Based on the midpoints of those ranges, Staff recommends adjustments to the costs of common equity for the electric operations of CILCO, CIPS and IP of 63, 64.5 and 34 basis points, respectively, to reflect the reduced risk that will result from the adoption of Rider EUA.

A summary of Staff's cost of common equity recommendations, including Ms. Freetly's estimates of the downward adjustments to the required costs of common equity of CILCO, CIPS and IP necessary to reflect the reduced risk that would result from the adoption of Riders GUA and EUA is on Staff Ex. 20.0, Schedule 20.02. (Staff Ex. 20.0, pp. 19-21)

Ameren witness Craig D. Nelson criticizes Staff's recommendation to adjust the rate of return downward to reflect the reduced risk that would result from the AIUs being allowed to recover uncollectibles via an uncollectibles rider. (Ameren Ex. 26.0 (Revised), pp. 14-20) Mr. Nelson claims that there should be zero impact on the return on equity because the Company is as likely to over recover as under recover. This argument implies that investors are risk neutral; that is, investors are indifferent between investments with different levels of risk as long as those investments have the same expected return. This position is contrary to financial theory on the trade off between risk and return. Even if Mr. Nelson's speculation that investors expect that the Companies would not under-recover uncollectibles expense even in the absence of riders EUA and GUA is correct,[67] the increased certainty of uncollectibles cost recovery still results in a reduction in risk and, thereby, a cost reduction to the cost of common

[67] Of course, the proportion of uncollectible expense investors expect the Companies to recover is not observable; therefore, it can only be estimated. It cannot be known with certainty.

equity. Investors prefer more certainty (or alternatively less uncertainty). Since the uncollectibles riders reduce uncertainty, investors would be willing to accept a lower return on their investment in the Companies.

As explained in Ms. Freetly's direct testimony, financial theory posits that investors require higher returns to accept greater exposure to risk. Conversely, the investor-required rate of return is lower for investments with less exposure to risk. In the simplest terms, risk is uncertainty of return. Hence, the return required by investors is lower for investments with less uncertainty. Since the Riders GUA and EUA remove the uncertainty associated with the recovery of uncollectibles, Riders GUA and EUA also reduce the investor-required rate of return. (Staff Ex. 20.0, pp. 21-22)

Mr. Nelson claims that the riders provide reciprocal benefits to shareholders and ratepayers. (Ameren Ex. 26.0 (Revised), p. 16) The uncollectibles riders shift the risk of under recovery of uncollectibles expense from investors to the customers who pay their bills. Essentially, the riders require rate payers who pay their bills to provide a guarantee to the AIUs that all of their uncollectibles expense will be recovered. If ratepayers are compensated for the guarantee that they will provide the Companies' investors, Mr. Nelson would be correct that ratepayers would get a benefit from providing this guarantee to the Companies and their investors.[68] However, Ameren seeks to deny ratepayers that compensation. (Staff Ex. 20.0, p. 22)

Mr. Nelson claims that Staff's proposed adjustment to the return on equity is an indirect approach to ensure that the Companies continue to under recover uncollectibles and is punitive in nature. He is wrong. The uncollectible riders guarantee the AIUs

[68] Such compensation would be in the form of lower rates vis-à-vis those that would exist absent the uncollectible riders.

recovery of uncollectible expenses, thereby reducing the uncertainty of cost recovery. Guarantees have costs in the financial markets. For example, the AIUs entered into a credit agreement with financial institutions, under which the latter agree to issue letters of credit to guarantee the AIUs' financial obligations to counterparties. In exchange for those letters of credit, the AIUs pay the issuing financial institutions a fee. Similarly, the Companies are asking its customers to guarantee the recovery of uncollectible expenses through the rider mechanism. Hence, like the financial institutions that require compensation for providing guarantees, AIUs' ratepayers also should be compensated for providing a guarantee.

In summary, a reduction to the Companies' authorized rates of return for the implementation of Riders GUA and EUA is appropriate on two grounds. First, the uncollectible riders shift the risk of under recovery of bad debt from the investors, whose return requirements decline with the reduction in uncertainty. Hence, the adjustment to the cost of equity reflects investor expectations of reduced uncertainty due to the collection of uncollectibles through riders. Second, the reduced cost of equity also provides compensation to customers for the risk they are absorbing through the guarantee they are providing to the AIUs and their investors.

Further, basing the magnitude of the rate of return adjustment on the amount of uncollectibles is appropriate not only because the amount of risk that is shifted from investors to ratepayers is related to the amount of uncollectibles, but it also provides the AIUs with a financial incentive to reduce uncollectibles. The lower the amount of uncollectibles, the lower the downward adjustment to the rate of return related to Riders GUA and EUA.

Ameren witness Lee Nickloy states that Moody's was aware of the passage of this rider prior to its recent upgrade of the AIU's credit ratings and no further upgrade could be expected. (Ameren Ex. 28.0, p. 9) Moody's upgrade to the AIUs' credit ratings directly affects the cost of the AIUs' credit facilities and will affect the cost of future debt issues. Nevertheless, that upgrade does not affect the starting point for analysis of the AIUs' costs of common equity: the costs of common equity of the Gas and Electric samples. Staff used the effect of the riders on credit ratings as one proxy of the effect of the riders on cost of common equity. Staff did not adjust the costs of the Companies' debt. Therefore, the Moody's reflection of the passage of the bad debt rider legislation does not eliminate the need to adjust the costs of common equity of the Gas and Electric samples. (Staff Ex. 20.0, p. 25)

g. Other

G. Recommended Overall Rate of Return

1. CILCO Electric

Staff recommends an 8.28% rate of return on rate base for CILCO's electric delivery services, which reflects a 10.38% rate of return on common equity for CILCO's electric operations. (Staff Ex. 19.0R, Schedule 19.01 CILCO)

Staff Proposal for CILCO Electric

March 31, 2009

Capital Component	Balance	Percent of Total Capital	Cost	Weighted Cost
Short-term debt	$32,017,993	5.60%	2.50%	0.14%
Long-term debt	271,691,990	47.49%	6.69%	3.18%
Preferred equity	18,893,282	3.30%	4.61%	0.15%
Common equity	249,457,171	43.61%	10.38%	4.53%
Bank Facility Fees				0.28%
TOTAL	$572,060,436	100.00%		8.28%

2. CIPS Electric

Staff recommends an 8.06% rate of return on rate base for CIPS' electric delivery services, which reflects a 10.14% rate of return on common equity for CIPS' electric operations. (Staff Ex. 19.0R, Schedule 19.01 CIPS)

Staff Proposal for CIPS Electric

December 31, 2008

Capital Component	Balance	Percent of Total Capital	Cost	Weighted Cost
Short-term debt	$58,098,936	5.91%	1.50%	0.09%
Long-term debt	397,751,866	40.44%	6.49%	2.62%
Preferred equity	48,974,984	4.98%	5.13%	0.26%
Common equity	478,676,606	48.67%	10.14%	4.94%
Bank Facility Fees				0.15%
TOTAL	$983,502,392	100.00%		8.06%

3. IP Electric

Staff recommends a 9.05% rate of return on rate base for IP's electric delivery services, which reflects a 10.44% rate of return on common equity for IP's electric operations. (Staff Ex. 19.0R, Schedule 19.01 IP)

Staff Proposal for IP Electric

March 31, 2009

Capital Component	Balance	Percent of Total Capital	Cost	Weighted Cost
Short-term debt	$10,791,502	0.45%	3.02%	0.01%
Long-term debt	1,307,983,675	54.11%	7.83%	4.24%
Preferred equity	45,786,945	1.89%	5.01%	0.09%
Common equity	1,052,636,039	43.55%	10.44%	4.55%
Bank Facility Fees				0.16%
TOTAL	$2,417,198,161	100.00%		9.05%

4. CILCO Gas

Staff recommends a 7.95% rate of return on rate base for CILCO's gas delivery services, which reflects a 9.64% rate of return on common equity for CILCO's gas operations. (Staff Ex. 19.0R, Schedule 19.01 CILCO)

Staff Proposal for CILCO Gas

March 31, 2009

Capital Component	Balance	Percent of Total Capital	Cost	Weighted Cost
Short-term debt	$32,017,993	5.60%	2.50%	0.14%
Long-term debt	271,691,990	47.49%	6.69%	3.18%
Preferred equity	18,893,282	3.30%	4.61%	0.15%
Common equity	249,457,171	43.61%	9.64%	4.20%
Bank Facility Fees				0.28%
TOTAL	$572,060,436	100.00%		7.95%

5. CIPS Gas

Staff recommends a 7.69% rate of return on rate base for CIPS' gas delivery services, which reflects a 9.38% rate of return on common equity for CIPS' gas operations. (Staff Ex. 19.0R, Schedule 19.01 CIPS)

Staff Proposal for CIPS Gas

December 31, 2008

Capital Component	Balance	Percent of Total Capital	Cost	Weighted Cost
Short-term debt	$58,098,936	5.91%	1.50%	0.09%
Long-term debt	397,751,866	40.44%	6.49%	2.62%
Preferred equity	48,974,984	4.98%	5.13%	0.26%
Common equity	478,676,606	48.67%	9.38%	4.57%
Bank Facility Fees				0.15%
TOTAL	$983,502,392	100.00%		7.69%

6. IP Gas

Staff recommends an 8.70% rate of return on rate base for IP's gas delivery services, which reflects a 9.64% rate of return on common equity for IP's gas operations. (Staff Ex. 19.0R, Schedule 19.01 IP)

Staff Proposal for IP Gas

March 31, 2009

Capital Component	Balance	Percent of Total Capital	Cost	Weighted Cost
Short-term debt	$10,791,502	0.45%	3.02%	0.01%
Long-term debt	1,307,983,675	54.11%	7.83%	4.24%
Preferred equity	45,786,945	1.89%	5.01%	0.09%
Common equity	1,052,636,039	43.55%	9.64%	4.20%
Bank Facility Fees				0.16%
TOTAL	$2,417,198,161	100.00%		8.70%

V. PROPOSED RIDERS

A. Overview

B. Resolved Issues

1. Revisions to Rider S for PGA Uncollectibles

Ameren proposed that the uncollectibles costs associated with PGA revenues would be collected via the Uncollectibles Factor in Rider S, in effect mirroring the uncollectibles associated with Electric Power Supply under Rider PER. Since the revenue requirements in the current proceeding exclude uncollectibles costs associated with PGA revenues, Staff did not take issue with this mechanism for recovery. (Staff Ex. 1.0, pp. 37-38) Ameren and Staff also agreed that the uncollectibles percentage should be based on actual write-offs as compared to revenues for the period 2007, 2008 and year-to-date September 2009, as discussed above in Section III.B.5. Further, Ameren and Staff have agreed on the proper accounting for the revenues to be recorded under the Rider S revision. (Staff Ex. 1.0, pp. 38-39)

2. Exclusion of Electric Distribution Tax/Public Utilities Revenue Act Tax from Tax Additions Rider

The AIU initially proposed certain revisions to the Tax Additions Rider for the recovery of the Electric Distribution Tax. That proposal was withdrawn in rebuttal testimony. (Ameren Ex. 26.0 (Revised), pp. 20-21)

C. Contested Issues

1. Rider VGP

The AIU proposed Rider VGP to allow its customers to participate in "Green Energy" through the purchase of renewable energy credits ("RECs"). (Ameren Ex. 14.0E, pp. 6-8) Staff witness Ebrey opined in testimony that the program was not sufficiently designed or explained for Staff to recommend approval. (Staff Ex. 1.0, pp. 36-37) Ameren continued to discuss the accounting for the VGP Program in rebuttal testimony. (Ameren Ex. 39.0 (Revised), pp. 2-6) In its rebuttal, Staff detailed concern with the timing of acquisition of the RECs. (Staff Ex. 15.0, pp. 26-27) Ameren admitted that the REC procurement process has not yet been designed and that they are proposing to maintain flexibility regarding the procurement. (Ameren Ex. 67.0 (Revised), pp. 3-5) Staff's concerns with the timing of the RECs' acquisition and the treatment of the variance between anticipated and actual participation levels have not been addressed by Ameren. Thus, Staff remains unable to recommend approval of the proposed Rider VGP.

VI. COST OF SERVICE/REVENUE ALLOCATION

A. Overview

B. Resolved Issues

1. Gas

Staff found the Company's Cost of Service (COS) Studies for gas to be acceptable guidance tools for setting gas rates in these dockets. The COS Studies reflected changes in customer class definitions as Ameren proposed a more common pricing goal for all three gas utilities as directed by the Commission in the Final Order of the Company's last rate case. (Docket Nos. 07-0585 – 07-0590 (Cons.), September 24, 2008, pp. 283, 290, 335-336; Staff Ex. 9.0, p. 4)

2. Electric

3. Gas

a. Weather Normalization

Staff did not object to the use of the 10-year period for weather normalizing data in these dockets and Staff does not object to the use of historical data from the Champaign-Urbana weather station. (Staff Ex. 9.0, pp. 6-7)

b. Billing Determinants

Staff testified that the change to test year billing determinants, as proposed by Ameren, is appropriate based on a proposal for reclassification. The billing determinant adjustments will realign proposed revenues so that the revenue requirement that is approved in the final order of these dockets will more accurately reflect test period sales. (Staff Ex. 9.0, p. 9)

c. Rate Classes

Staff agreed with Ameren's proposed rate classes. The rate classes remain essentially the same; however, in order to achieve a more common and uniform rate structure, Ameren has proposed reclassifying certain non-residential AmerenCILCO and

AmerenCIPS customers based on the existing AmerenIP non-residential rate class definitions. (Staff Ex. 9.0, p. 9)

B. Contested Issues

1. Electric

a. AIUs' Cost of Service Studies

The cost of service studies proposed by the AIUs should be adopted by the Commission with one key revision. That change would allocate primary lines and substations according to coincident peak (CP) demands, rather than non-coincident (NCP) demands, as the Companies propose.

b. Allocation of Costs to Customers Receiving Service at Voltages 100+ Kv

See Sections VII.C.2.a. and d. below.

c. Allocation of Cost of Primary Distribution Lines and Substations

The Companies' proposal to allocate primary distribution lines and substations according to NCP demands should be replaced by a CP approach proposed by Staff. The problem with the NCP is that it does not accurately reflect how the costs of distribution lines and substations are incurred. The NCP allocator is driven by the maximum demands of individual classes whenever they occur whether during a peak or off-peak period. These individual class demands do not necessarily shape the costs of primary distribution lines and substations which are generally constructed to serve the demands of multiple rate classes that collectively use those facilities. This is evident from the AIUs' own statements in the discovery process acknowledging that distribution facilities are not designed "based on rate classes," but instead "design aggregate load based on locale." (Staff Ex. 7.0, pp. 6-7)

The AIUs provide additional statements that acknowledge these facilities serve the collective demands of multiple classes rather than individual class NCP demands. For example, they state that primary lines and substations are designed “based on the collective demands of ratepayers from all rate classes served at that locale.” (Staff Ex, 7.0, p. 7, citing AIU Response to Staff DR PL 4.02) For both distribution lines and substations specifically, the Companies admit “it is reasonable to assume that they would serve multiple rate classes.” They go on to concede that “it is unlikely” that either “would serve a single rate class but it could occur.” (*Id.*)

These admissions have direct implications for allocating primary distribution line and substation costs. If these facilities were to serve customers from a single rate class, then clearly, the peak demands of individual classes would determine their size and ultimate cost. However, as the Companies acknowledge, individual facilities serve customers from numerous rate classes. Therefore, the design would have to take into account the combined CP demands of customers from all classes served. (*Id.*)

The Companies’ references to local demands as cost drivers do not justify the use of an NCP approach for primary lines and substations. Neither a CP allocator nor an NCP allocator measures “local” demands. Each seeks to represent demands on a utility-wide basis. The key difference is that the CP reflects the collective demands of multiple rate classes while the NCP is based on the peak demands of individual rate classes. The issue for primary lines and substations concerns which of the two allocators reflects the collective peak demands of multiple rate classes at a local level. Since the CP focuses on multiple rate classes and the NCP on individual rate classes, the CP is the more cost-based approach. (*Id.*, pp. 7-8)

The lighting class illustrates the shortcomings of an NCP allocator for primary distribution lines and substations. This class which uses most of its electricity during off-peak, evening hours is penalized by the NCP which factors those full off-peak demands into the development of the allocator. Those off-peak demands are used to allocate to lighting customers the costs of primary distribution lines and substations which the AIUs admit are designed "based on the collective demands of ratepayers from all rate classes served at that locale." This clearly conflicts with cost causation principles. (*Id.*, p. 8)

The more equitable approach for lighting and other classes, as well, is to allocate primary distribution lines and substations according to CP demands. The CP allocator represents the sum of individual class demands that occur at the time that the system as a whole reaches its peak level of demand. The individual class shares represent the contribution of each to this overall peak demand on the system. The CP is the allocator that most accurately represents the combined demands of multiple rate classes and is, therefore, most appropriate for distribution lines and substations that collectively serve customers from different classes. (*Id.*, p. 9)

Ameren witness Althoff takes issue with Staff's CP alternative. She begins by acknowledging that Staff is "correct" in arguing "the AIUs' facilities are built to serve demands based on locality and that geographical locations do encompass customers in multiple rate classes." (Ameren Ex. 41, p. 3) Nevertheless, she insists that dependence on localized demands justifies using an NCP, rather than a CP, approach for substations and primary lines. Her argument is based on the process of elimination; since localized demands may not coincide with systemwide demands, Ms. Althoff argues that the CP approach should not be used. Ms. Althoff considers the NCP approach is a better fit because "[t]he NCP demand more closely matches the load diversity on these more localized systems." (*Id.*, p. 4)

Ms. Althoff confuses the issue. She criticizes the CP allocator for not reflecting localized demands but fails to note that neither does the NCP allocator which is calculated on a system-wide basis. Ms. Althoff fails to explain why system-wide NCP demands correspond more closely with the localized demands that drive investments in primary lines and substations than CP demands. In fact, CP demands are more appropriate because as Ms. Althoff acknowledges, primary lines and substations "encompass customers in multiple rate classes." (Staff Ex. 21.0, pp. 5-6)

Ms. Althoff also criticizes the CP approach for allocating "zero costs" of primary lines and substations to lighting customers. Ms. Althoff considers this inappropriate because "[t]he AIUs have substations and circuits that indeed register their local peaks in non-summer periods." (Ameren Ex. 41, p. 5) Ms. Althoff goes on to acknowledge "that lighting (DS-5) customers are unlikely to contribute to a summer peak demand." But, she maintains that lighting customers use primary lines and substations and, therefore, "should be allocated some costs for the use of these assets." (*Id.*, pp. 5-6)

Ms. Althoff focuses on the unique characteristics of the lighting class, noting, for example, that "the "dusk to dawn" provision of the rate provides reasonable assurance that the customers will not contribute to the summer peaks (which typically occur between 2 p.m. and 7 p.m. – summer daylight hours). However, she indicates that for other months, the class' peak demand coincides with the system peak demand. Ms. Althoff then states that "while the NCP demand allocation may allocate too much to the lighting class, the CP demand allocation will allocate too little." (*Id.*, p. 5)

Ms. Althoff's statement is notable because it implies that the NCP allocates too much to the lighting class. Since the CP approach comports most closely with the way these costs are determined, that is the methodology that should be used.

Ms. Althoff also seeks to use the example of grain drying customers as support for the NCP approach. She cites testimony from Company witness Jones that a single CP allocator would fail to recognize that "several circuits that serve grain drying customers in fact peak during the fall grain drying season." (*Id.*, p. 6)

This argument presents problems. For one, Ms. Althoff does not identify the circuits or provide a number to accompany her claim of "several." This makes it difficult to determine whether these circuits comprise a significant share of the total investment in primary lines. Second, it is not clear why Ms. Althoff is focusing on cost allocations to grain dryers since these customers do not constitute a separate class for allocating the cost of service. Instead, they constitute subclasses of the DS-3 and DS-4 classes and receive cost allocations in conjunction with all other customers within their class. Furthermore, the rate limiter in effect for grain dryers is not directly based on the cost of service, but rather is driven by bill impacts concerns for a subgroup of DS-3 and DS-4 customers. Thus, grain dryers are not a relevant example for this cost of service issue. (Staff Ex. 21.0, p. 9)

Ms. Althoff goes on to argue that CP demands are not appropriate for allocating primary lines and substations to DS-3 and DS-4 customers. She contends that these classes "are not weather sensitive" and could peak during various times throughout the year. Since the AIUs' CP "occurs in the summer season reflecting the impact of weather," Ms. Althoff considers the CP's failure to capture these off-peak DS-3 and DS-4 demands a problem. (Staff Ex. 21.0, pp. 9-10)

Ms. Althoff's concerns should be dismissed. To the extent that demands by these customers take place during off-peak periods, their contribution to investments in primary lines and substations will be reduced. This off-peak usage should be rewarded not punished which would be the case under the CP rather than the NCP allocator. (*Id.*, p. 10)

IIEC witness Stowe also weighs in on this issue, siding with the Companies on behalf of the NCP over the CP approach. Mr. Stowe discusses the Lighting Class, arguing that the CP method is flawed because it does not allocate costs to the Lighting Class. He goes on to state that "there are conditions wherein the CP method fails to allocate costs to certain classes because, though they use the distribution system, they do not use electrical power at the time of the system peak demand. The NCP method, however, does not suffer from this deficiency, and recognizes the collective demand of every rate class regardless of when it occurs." (IIEC Ex. 8.0-C, p. 22)

Mr. Stowe's argument is incorrect. For one, Staff is not advocating the CP approach for all distribution costs, only those pertaining to primary lines and substations. Second, the cost of service issue should not focus on the amount of costs the CP allocates to any individual class, but rather on whether that allocation most accurately reflects how costs are caused by AIU ratepayers. The NCP allocator is based on the sum of individual class demands based upon the separate peaks of each rate class. So, if one class uses less when the system peaks and uses most when overall demand is low, the NCP will allocate system costs to that class based upon its off-peak usage. The problem is that equipment such as primary lines and substations are generally constructed to serve multiple rate classes, not just one class at a time. And the demands of multiple classes more closely correspond to CP rather than NCP demands. Therefore, the most reasonable, cost-based approach is to allocate the cost of this equipment according to the collective peak demands of all rate classes. (Staff Ex. 7.0, pp. 6-7)

Mr. Stowe may be concerned that the Lighting Class is underrepresented in this framework, but it should be remembered that a class with little or no demand when system demand is highest and peak demands when overall usage is low does not cause these costs to be incurred. Thus, the CP is clearly superior to the NCP for allocating costs associated with primary lines and substations.

d. Allocation of Electric Distribution Tax/Public Utilities Revenue Act Tax

The proposal to allocate distribution taxes by usage as proposed by the Company and Staff is consistent with cost-causation and should be adopted in this proceeding.

The Companies advocate a usage-based approach because according to AIU witness Jones, the level of distribution taxes imposed on utilities has been calculated on a per-kWh basis since December 1997. (Ameren Ex. 16.0E (Revised), p. 11) So, for more than a decade, usage has determined the amount of distribution taxes collected from ratepayers. Since usage is the driver, cost-causation principles would argue for allocating these costs on a per-kWh basis. However, that has not been the case until now because distribution taxes are currently allocated according to plant in service. This approach placed a greater share of responsibility for these costs on smaller customers. (Staff Ex. 7.0, p. 10)

The language of the relevant legislation on this issue clearly shows that the Illinois General Assembly made a conscious decision to change the way the distribution tax is determined. According to the Act:

> This amendatory Act of 1997 is intended to provide for a replacement for the invested capital tax on electric utilities, other than electric cooperatives, and replace it with a new tax based on the quantity of electricity that is delivered in this State. The General Assembly finds and declares that this new tax is a fairer and more equitable means to replace that portion of the personal property tax that was abolished by the Illinois Constitution of 1970 and previously replaced by the invested capital tax on electric utilities, while maintaining a comparable allocation among electric utilities in this state for payment of taxes imposed to replace the personal property tax. (35 ILCS 620/1a, P. 90-561, eff. 1-1-98)

Thus, the General Assembly decided to replace a tax based on invested capital with a tax determined by usage.

The proposal to allocate distribution taxes from a plant allocator to a usage allocator would shift responsibility for these costs from smaller to larger customers on the system. For example, large DS-4 customers account for 43% of system usage and, therefore, would be allocated 43% of these costs in contrast to the 8% they now pay. The allocation to Residential DS-1 customers would decline from 56% to 30% of these costs. (Ameren Ex. 16.0E (2^{nd} Revised), p. 8)

The IIEC disagrees with the usage-based approach and argues instead that the current method of allocating distribution taxes among rate cases according to plant in service should continue to be employed in this case. (IIEC Ex. 1.0-C, p. 24) IIEC witness Stephens cites precedent for this approach by noting that "[i]n each round of delivery service rate cases since enactment of the 1997 law, the various Ameren companies have proposed, and the Commission has approved, the cost study allocation of the Public Utilities Revenue Act ("PURA") tax on the same basis as the overall distribution plant is allocated." (*Id.*, p. 17)

The IIEC argument is flawed because cost causation, rather than precedent, should be the deciding factor in the allocation process. The Commission has a longstanding principle of basing rates on cost causation principles. If an existing method of allocating a cost that the Commission has approved is not cost-based, then the most equitable and efficient solution is to adopt a cost-based approach. (Staff Ex. 21.0, p. 3)

The IIEC also argues that the continued allocation of distribution taxes according to plant in service is justified on cost principles. IIEC witness Stephens claims that "the largest driver of any utility's PURA Tax responsibility is its level of invested capital used to develop the tiered charges in the 1997 deregulation law, which are in use today." (IIEC Ex. 1.0-C, p. 24) Mr. Stephens asserts that the current levels of the tax "is primarily a function" of the past levels of plant assets. He states that the tier levels used for the taxes "have been custom-designed to collect approximately the same level of tax revenue from each utility, and in total, as the utilities had previously based on invested capital." He goes on to contend that the overall increases in collections under the tax are based on the "lesser of 5% or Consumer Price Index." (*Id.*, p. 21)

Mr. Stephens' argument is unconvincing. While the starting point for the tax levels after the amendatory act corresponded to previous tax levels that were based on invested capital, the yearly changes for taxes as a whole for all Illinois utilities, as Mr. Stephens acknowledges, are not. Each year the total amount of distribution taxes collected by utilities increases by the lesser of 5% over the existing level or by the yearly consumer price increase. Neither of these factors bears any relationship to plant investments. More importantly, the share of the total distribution taxes for Illinois utilities paid by any one utility is based solely on their share of deliveries by Illinois electric utilities. (Staff Ex. 21.0, pp. 3-4)

Furthermore, plant in service is no longer considered in the calculation. So, if the level of plant were to double or to decline by half, that specific change would have no impact on the utility's distribution tax. In contrast, the level of deliveries by electric utilities does directly affect distribution taxes. If a utility's level of deliveries goes up relative to other electric utilities in Illinois, its share of distribution taxes will increase. If its relative level of deliveries decline, the utility's share of the distribution tax total will fall. Clearly, usage is the driver now. (*Id.*, p. 5)

In rebuttal, IIEC witness Stephens continues to insist that the distribution tax is related to plant, rather than usage, arguing that "the PURA [distribution] Tax is caused primarily by the level of invested capital existing for each utility at the time the 1997 deregulation law was enacted. (IIEC Ex. 5.0-C, p. 10) He goes on to contend that "the kWh tiers and charges were simply a formulaic construct to approximate the same tax revenue as each utility had provided under the Invested Capital Tax. Since the invested capital of the utilities in 1997 caused a specific level of PURA Tax for each utility, it would not have mattered whether the legislation achieved its revenue neutrality by assigning per kWh rates, per kW rates, or had simply enumerated each utility's starting tax level in the law." (*Id.*, p. 10)

There is no doubt that the General Assembly initially set the level of PURA taxes for each utility calculated on a usage basis approximately equal to the level under the previous plant-based method. However, the General Assembly made it explicitly clear that this tiered method of allocating PURA taxes to utilities would be based on a going-forward basis according to usage, not plant. There is no ambiguity in the Legislature's language which states the clear intent "to provide for a replacement for the invested capital tax on electric utilities, other than electric cooperatives, and replace it with a new tax based on the quantity of electricity that is delivered in this State." The Act goes on to state that in the General Assembly's view, this usage-based approach is "fairer and more equitable." (35 ILCS 620/1a, P. 90-561, eff. 1-1-98) In fact, it could be argued that a continued allocation of these costs by the plant in service method which the General Assembly explicitly rejected would directly conflict with the intent of the law. (Staff Ex. 21.0, p. 4)

e. NCP Class Demands

See Section VI.c.1.c. below.

f. Other

2. Gas

a. Account 904

b. Storage Cost Allocations Between Sales and Transportation Customers

Ameren allocates the costs of its underground storage facilities to both sales customers and transportation customers. Ameren witness Normand proposes to allocate underground storage costs to transportation customers based on their ability to withdraw gas on a peak day:

> Underground storage plant facilities were segregated into a portion that supports the delivery function applicable to all sales customers and a separate portion assignable to transportation customers based on their ability to withdraw gas from their transportation banks on a peak day...The percentage allocation to transportation for each utility…was based on the transportation customers' ability to rely on these facilities to serve 20% of their peak day usage with bank withdrawals. (Ameren Ex. 16.0G, p. 10)

Mr. Normand first allocates costs to transportation customers and then holds sales customers responsible for the residual costs. (Tr., pp. 368-369, December 15, 2009)

Staff has no objections to allocation of these costs based on the ability to withdraw gas on a peak day. However, while Mr. Normand reasonably allocates these costs based on ability to withdraw gas on a peak day, he measures that ability as 20% of transportation customers' usage rather than the smaller amount allowed in the tariff, which is 20% of a customer's Daily Confirmed Nomination ("DCN") [69] for GDS-4 customers.[70] (Staff Ex. 27.0R, p. 36) Nominations are the amount of gas scheduled for delivery on a pipeline to the LDC system. DCN is the amount that the pipelines have confirmed will be delivered. (*Id.*, p. 37) Ameren treats any volume of gas that a customer uses above its DCN as a bank withdrawal. Therefore, on days where a customer expects to withdraw gas from its Rider T bank as is assumed in allocating storage cost responsibility, it nominates a volume of gas *less* than its anticipated usage. Thus, as Company witness Dothage concedes, DCN will be less than usage and 20% of DCN will be less than 20% of usage. (Tr., pp. 856-857, December 17, 2009) The practical result of Mr. Normand using 20% of usage is to over-allocate storage costs to transportation customers. (Staff Ex. 27.0R, p. 37)

Consistent with the Companies' tariffs that provide that transportation customers may withdraw 20% of their peak day DCN, Staff recommends that these customers be allocated the share of storage costs based on 20% of DCN rather the 20% of their peak

[69] **Daily Confirmed Nomination (DCN)**
Daily Confirmed Nomination is the volume a transportation Customer nominates and delivers to the Company's delivery system for any single day. The absence of a Daily Confirmed Nomination is equivalent to a Daily Confirmed Nomination of zero. Such Deliveries shall reflect adjustments for losses on Company's gas system. (Ill. C. C. No. 20**,** 1st Revised Sheet No. 25.001)

[70] [For daily-balanced customers]: During a Critical Day, the maximum amount to be withdrawn from Customer's Bank shall be 20% of DCN. (Ill. C. C. No. 20**,** 2nd Revised Sheet No. 25.005)

day usage. Using 20% of DCN changes the storage allocator in Ameren Ex. 27.3 from 18.00% for AmerenCIPS to 14.02%, from 5.53% for AmerenCILCO to 3.96% and from 5.21% for AmerenIP to 3.80%. (*Id.*, p. 38)

c. Other

VII. RATE DESIGN/TARIFF TERMS AND CONDITIONS

A. Overview

B. Resolved Issues

1. Gas and Electric

a. Combining Customer and Meter Charges

One proposal in the Companies' initial filing was to replace the separate customer and meter charges with a single fixed charge on customer bills. The Companies argued that two charges are unnecessary because no meter providers serve retail customers in the AIUs' service territories. (Staff Ex. 7.0, pp. 22-23)

Staff had strongly opposed this proposal. Staff contended that the Commission has gone to considerable lengths to unbundle customer charges for retail customers to create a potential market in which future competitors may participate. Retreating from that decision by combining the meter and customer charges on ratepayer bills would impede future efforts to build the market for unbundled metering. It would also deny ratepayers useful information the unbundling of metering costs provides about this important component of their bills. (*Id.*, p. 23)

The Company subsequently withdrew this proposal in favor of the current approach as Staff recommends. (Ameren Ex. 40.0 (2^{nd} Revised), p. 15)

b. Customer Charge Label

In his direct testimony (Ameren Ex. 17.0G (Revised)), at lines 174-179, Company witness Millburg proposed to label the Customer Charge as "Fixed Monthly Charge" on customer bills. Mr. Millburg asserts that the label change should aid in customers' understanding of the bill component and the role the charge plays in supporting the Companies' fixed costs for their gas systems operations. Mr. Millburg further explained in his response to Staff DR CB 4.03 that when the Companies try to explain to a customer what a "Customer Charge" is, customer service representatives anecdotally describe it as "a fixed monthly charge that does not change with monthly usage." (Staff Ex. 10.0, p. 7)

Staff witness Boggs objected to the label change stating that the change would be more confusing to customers because the monthly charge will change from time to time due to charges that are, and will be, added to the Delivery Services customer charge. The charge may not always change monthly, but it will change nonetheless. (Staff Ex. 10.0, p. 8)

In his rebuttal testimony (Ameren Ex. 48.0 (Revised), p. 2), Mr. Millburg indicated that "The AIUs no longer propose to change the Customer Charge label to 'Fixed Monthly Charge' on either electric or gas customer bills. The AIUs, therefore, withdraw their proposal to amend the Terms and Conditions portions of their tariffs to make that change."

c. Uncollectibles Factors – Riders EUA and GUA

Staff witness Ebrey proposed that uncollectibles factors be set in this rate case for purposes of the Uncollectibles Riders EUA and GUA. (Staff Ex. 15.0, p. 28) Ameren witnesses Jones (Ameren Ex. 55.0 (Revised), pp. 22-23) and Millburg (Ameren

Ex. 58.0 (2nd Revised), pp. 4-5) provided calculations of those factors based on the AIU rebuttal calculations. Both Ameren witnesses stated that the factors should be updated to conform to the expense level authorized in the Final Order in this case. Staff witness Ebrey agreed that the final uncollectibles factors would need to be recalculated based on the findings related to uncollectibles expense in the Commission's Final Order. (Tr., p. 787, December 17, 2009)

2. Gas

a. Rate Limiter or Capping Mechanism

Staff agreed with Ameren's proposal to move each rate class closer to its revenue requirement by assuming an equalized revenue requirement for each rate class within each LDC. Staff agreed with Ameren's proposal to limit the amount of the proposed rate increase for each rate class to a specified percentage over present rates so as not to create adverse bill impacts. (Staff Ex. 9.0, pp. 15-16)

b. Overall Rate Design (Scale to Final Revenue Targets)

Staff agreed with Ameren's proposed rate design. Ameren has taken into account Commission directives from its last rate order, reviewed bill impacts and Ameren is implementing a Capping Mechanism to moderate increases based on the goal of uniformity among the LDCs. (Staff Ex. 9.0, p. 18)

Staff submitted rate schedules that scale Ameren's proposed rates to final revenue targets by calculating the percentage difference between the Company's total revenue requirement and Staff's recommended revenue requirement. The percentage was then applied equally to Ameren's proposed charges as shown on Schedules 22.01 IP-G, 22.01 CILCO-G and 22.01 CIPS-G. Staff proposed rates based on Schedule 22.01 which reflect Staff's recommended revenue requirement. By applying the ratio across-the-board, each rate is equally affected by Staff's lower recommendation for the revenue requirement. Additionally, Schedule 22.01 can be modified to show the rates that result from the revenue requirement adopted in the Final Order. (Staff Ex. 22.0, pp. 6-8)

c. Interval Meter Data Access Fees

In his testimony (Ameren Ex. 17.0G (Revised)), at lines 211-213, Mr. Millburg initially indicated that the cost of the installation of a modem and associated equipment required to host the modem would cost a customer a one-time charge of $2,400 and a monthly fee of $5.00. In his response to Staff DR CB 1.01, Mr. Millburg replied that he learned the equipment costs used in preparing the one-time charge were outdated and incorrect. (Staff Ex. 10.0, p. 22) Mr. Millburg maintained that in order to collect, store and communicate the usage data from the gas meter into the Unbundled Services Management System ("USMS") on a daily basis, the following auxiliary equipment would need to be installed on the meter:

> If the meter lacks an electronic pressure corrector, a pulse accumulator would need to be installed. The pulse accumulator receives the usage information from the meter, converts it into electronic data, and stores the usage data at the meter until the remote inquiry is made through its built-in modem; or if the meter already has an electronic pressure corrector installed, a stand-alone modem must be added to transmit the stored usage data to the USMS. (*Id.*, p. 23)

According to the information that Mr. Millburg supplied in his response to Staff DR CB 1.01, the installation charges for meters without an Electronic Pressure Corrector - Pulse Accumulator amount to $1,944. The installation charges for meters already equipped with an Electronic Pressure Corrector - Stand-alone Modem amount to $812.25. (*Id.*)

In that same response, Mr. Millburg also supplied data that illustrated the monthly fee to collect the daily usage data by calling the modems at each meter from USMS. This data yielded a monthly cost to the Company of $4.95 based on a 30-day month.

Staff witness Boggs recommended approval of the Companies' proposal to charge customers who desire daily access to metered usage through USMS a one time fee of $1,944 when the Companies have to install an Electronic Pressure Corrector - Pulse Accumulator. Based on the information that Mr. Millburg provided in his response to Staff DR CB 1.01, this fee is equal to the materials and labor charge that would be incurred by the Companies multiplied by the excess facilities charge (1.9 times the labor and materials charge). (*Id.*, p. 24) An excess facilities charge applies because this equipment is not used to gather meter data for billing delivery service or supply service for smaller volume gas customers.

Mr. Boggs also recommended approval of the Companies' proposal to charge customers a one time fee of $812.25 when they need to install a Stand-alone Modem. Based on the information that Mr. Millburg provided in his response to Staff DR CB 1.01, this fee is equal to the materials and labor charge that would be incurred by the Companies multiplied by the excess facilities charge. (*Id.*, p. 23)

Finally, Mr. Boggs recommended approval of the Companies' proposed $5.00 monthly fee assessment to customers for collecting the daily usage data by calling the modems at each meter from the USMS. Based on the information that Mr. Millburg provided in his response to Staff DR CB 1.01, it takes an average of five minutes for the data to be transferred from the meter and uploaded into USMS. (*Id.*, pp. 24-25) The Companies' current long-distance charges are 3.3 cents per minute. An average of 30 (one per day) calls per month, averaging five minutes per call at 3.3 cents per minute equals $4.95, which is rounded up to $5.00 for inclusion in this tariff.

d. Calculation of "Highest Average Daily Use"

Staff agreed with Ameren's proposal to change the parameters for non-residential customers that establish minimum and maximum levels of usage for GDS-2, GDS-3 and GDS-4. Service under GDS-2 would be available to any non-residential customer whose highest average daily usage is less than 200 therms per day in any monthly billing period during the prior 12 monthly billing periods. Ameren proposed an average daily usage equal to or greater than 200 therms per day yet less than 1,000 therms per day for GDS-3 customers and an average daily usage equal to or more than 1,000 therms per day would classify a customer as a GDS-4 customer. (Staff Ex. 9.0, pp. 7-8)

e. Transportation Tariff (Rider T)

(1) NAESB Intraday Nomination Cycles

Nomination is how transportation customers schedule gas deliveries from a pipeline onto the LDC's system. In the previous AIU rate case Order, the Commission ordered that AIU expand its intra-day nominations. The Commission also required the Company to address this issue in its filing for the instant case:

> When preparing its next gas rate cases, AIU should determine the cost of providing all 4 nomination cycles and provide that information with its rate filing. The Commission would also hope that those favoring the addition of nomination cycles would offer evidence of specific/concrete benefits associated with additional nomination cycles. The Commission hopes to use such information to weigh the cost and benefits of implementing the 4 NAESB nomination cycles in AIU's next gas rate cases. (Order, Docket Nos. 07-0585 - 07-0590 (Cons.), September 24, 2008, p. 323)

Ameren witness Dothage provided this analysis in Ameren Exhibit 22.0G and Ameren Exhibit 22.2. Mr. Dothage estimated that the fixed costs of such a change would be $75,000 and the annual variable costs would be $250,000. (Ameren Exhibit 22.0G, pp. 4-8)

Staff witness Sackett objected to Mr. Dothage's analysis. The data provided by Ameren in response to Staff DR DAS 1.22 shows that Ameren has received and processed these nominations with its current system and staffing levels on every day of the week and even on holidays in all three intra-day nomination cycles. (Staff Ex. 14.0, p. 11) Additionally, Ameren's response to Staff DR DAS 4.05 shows that it has not turned away any intra-day nominations because it was unable to meet them with its current best efforts. (*Id*., p. 14) Therefore, absent an increase in nominations, it follows that the existing manual process and staffing levels are sufficient. (*Id.*) Consequently, Mr. Sackett concludes that "these personnel could continue to be tasked with this responsibility on a going forward basis." (*Id.*, p. 12)

After discussion with both Ameren and CNE, an agreement was reached that incorporated a new "Same Day" nomination schedule without expanding the computer systems. (See Staff Group Ex. 1-HH) Staff supports this agreement. The new tariff language is below:

> **4. Same-Day**
> Customer desiring a change in Nomination for transportation of Customer-Owned Gas after the Intra-Day deadline specified above shall notify Company by 7:30 A.M. CST of the business day on which the Nomination is to take effect, subject to confirmation by the pipeline. Company may accept such change to Customer's Nomination if the Company determines in its sole discretion that such a change to Nomination will not adversely impact the operation of the Company's gas system or adversely impact Company's purchase and receipt of gas for other Rates or Riders. The Company will use its best effort to accept nominations for transportation of

> Customer-Owned Gas at all other times, subject to confirmation by the interstate pipeline.

(2) Notice for OFOs and Critical Days

In its order from AIU's previous rate case, the Commission agreed with AIU that there are portions of its system that cannot support a 24-hour notice:

> A review of Ameren Ex. 54.7, however, appears to explain at least in part why AIU may not be able provide much notice *in some isolated areas of its gas distribution systems*. Clearly, there are multiple communities served by AIU which are connected to only one interstate gas pipeline. Under such circumstances, the unexpected loss of supply from the interstate pipeline could endanger system integrity so quickly that the amount of notice that CNE-Gas appears to be contemplating would not be feasible. (Order, Docket Nos. 07-0585 - 07-0590 (Cons.), September 24, 2008, p. 345, emphasis added)

However, the Commission required Ameren to address notifications in its filing for the instant case:

> Other portions of AIU's distribution systems, however, may be well suited to the provisioning of additional notice by AIU before declaring an OFO or Critical Day. Such areas include where storage resources exist and/or there are multiple interconnections with interstate pipelines. While accepting AIU's OFO and Critical Day notice provisions for purposes of this proceeding, the Commission directs AIU to provide in its next gas rate case filing an analysis of its distribution systems *identifying those areas that would not be immediately affected by a single event on the associated interstate pipeline(s).* The analysis must also *address with specifics* whether AIU could provide notice *in such areas* comparable to the notice provided by Nicor and Peoples. (Order, Docket Nos. 07-0585 - 07-0590 (Cons.), September 24, 2008, p. 345, emphasis added)

Ameren provided a two-part analysis prepared by Ms. Seckler in Ameren Exhibit 23.0G, pp. 3-10, and Ameren Exhibit 23.1. Ms. Seckler evaluates the independent systems that are served by single sources and those served by multiple sources. She concludes that AIU cannot provide more notice because "if one supply source is disrupted there is insufficient alternative pipeline capacity or storage resources to serve the load and maintain system integrity." (Ameren Ex. 23.0G, p. 9)

CNE proposed tariff language to address AIU's concerns. Specifically, this language requires that Ameren notify the Commission each time it has to issue a notification of a CD or an Operational Flow Order ("OFO"). (CNE Ex. 1.0, p. 10)

Ameren witness Ms. Seckler accepted the tariff language suggested by CNE:

> The Company shall provide notice of a Critical Day and OFO as far in advance as reasonably possible, normally not less than two hours, unless the Company believes conditions warrant immediate implementation of the Critical Day or OFO. If the Company issues a Critical Day or OFO notice within 24 hours of the Critical Day or OFO taking effect, the Company will report to the Commission indicating why customer notice of less than 24 hours was necessary. (Ameren Ex. 45.0 (Revised), pp. 3-6)

Staff recommends that the Commission approve the language proposed by CNE and agreed to by Ameren, because this language addresses the primary concern raised by CNE. Staff also recommends that Ameren be required to provide a report with justification to the Director, Energy Division, within 24 hours of the declaration. (Staff Ex. 27.0R, p. 4)

Ameren witness Ms. Seckler proposed to change Staff's 24-hour justification to a 2-business day justification. "Adopting a two business day deadline for submitting the justification report would provide the AIUs with sufficient time to analyze the situation and produce the report. It also would make the report due during the Commission's and AIUs' normal business hours." (Ameren Ex. 65.0 (Revised), pp. 3-4)

Staff witness Sackett accepted this revision in response to Ameren DR AIU-ICC 14.18-20.

3. Electric

a. Rider PER

Ameren proposed a language change to Rider PER in 1st Revised Sheet No. 31.008. Staff witness Rukosuev objected to the original proposed change as it was written in unnecessarily broad language and did not provide clarity to all interested parties. In his direct testimony, Mr. Rukosuev proposed a modification that would add clarity without changing the substance of Ameren's current language. The modification would read as follows:

> The base Retail Supply Charges resulting from the ICC Order associated with Docket Nos. 09-0306 – 09-0311(Cons.) shall provide the initial baseline for changes in overall electric charges for any price classification. (Staff Ex. 8.0, p. 18)

Ameren accepted this modification regarding Rider PER. (Ameren Ex. 40.0R, pp. 19-20)

b. Rider RDC

In his direct testimony, Staff witness Rukosuev accepted Ameren's several minor language modifications to Rider RDC, 2nd Revised Sheet No. 38.001. Mr. Rukosuev agreed that the proposed language changes are required for consistency as they are necessary to clarify that "Demand" and "Billing Demand" are not interchangeable terms. (Staff Ex. 8.0, p. 17) In addition, Mr. Rukosuev identified an error in 2nd Revised Sheet No. 38.001 that required correction. Ameren accepted Staff witness Rukosuev's modifications regarding Rider RDC associated with the error correction. (Ameren Ex. 40.0R, pp. 19-20)

c. Rider BGS

In his direct testimony, Staff witness Rukosuev accepted Ameren's language modification to Rider BGS, 4th Revised Sheet No. 22. Mr. Rukosuev considered the proposed language change as necessary to clarify that "Demand" and "Billing Demand" are not interchangeable terms. (Staff Ex. 8.0, p. 17)

Also see Sections VII.c.2.b. and f. below.

d. Rider QF

In his direct testimony, Staff witness Rukosuev accepted Ameren's modification to Rider QF, 3rd Revised Sheet No. 50.002, which eliminated the ability of the AIUs to refuse to accept output from a qualifying facility when sale of output does not permit the AIUs to avoid costs. Mr. Rukosuev considered the removal of the paragraph as a positive move which removed a potential restriction on customers. (Staff Ex. 8.0, p. 23)

e. Rider HMAC

Based on Staff's review and adjustment to HMAC costs included in the revenue requirement for AmerenIP, Staff proposed that the BASE amount for purposes of the Rider HMAC Clause should be clearly set at $411,899 in the Final Order in this proceeding. (Staff Ex. 1.0, pp. 40-41) The AIU agreed with Staff's proposal. (Staff Ex. 15.0, p. 6)

f. Miscellaneous Tariff Language Changes

<u>Customer Terms and Conditions</u>

Ameren proposed language changes in the Terms and Conditions of Service section of its tariffs. The proposed changes are made to clarify that "Demand" and "Billing Demand" refer to different concepts and are, accordingly, not interchangeable. Ameren witness Jones, in response to Staff DR PR 1.03, clarified the intended difference between the two terms. Therefore, in his direct testimony, Mr. Rukosuev recommended approval of the proposed language changes to Customer Terms and Conditions since they are necessary and are essential for consistency and clarity. (Staff Ex. 8.0, p. 4)

Staff witness Boggs also recommended approval of the following changes in Staff Ex. 10.0:

1. The Companies' proposed wording modifications and date changes in the "Switching Suppliers" subsections;

2. The Companies' proposed $400 fee for customers whose service has been disconnected at the main because access to the meter was blocked;

3. The Companies' proposed language changes in the "Disconnection and Reconnection" subsection; and

4. AmerenCILCO's proposal to eliminate the references to GDS-6, if the Commission approves the elimination of GDS-6 for AmerenCILCO.

Standards and Qualifications

Ameren proposed language changes to paragraph 4(B) of its Standards and Qualifications for Electric Service, which imposes a $170 fee per meter read. Effectively, this section was amended to include a provision to require customers to provide a means for remote meter interrogation or to require a $170 meter reading fee when AIU's personnel do not have free access. (Staff Ex. 8.0, p. 4) However, in his direct testimony, Mr. Rukosuev emphasized his concerns with regard to the proposed language change because it did not limit the proposed fee to non-residential customers explicitly. (*Id*.) In response to Staff DR GER 2.20, Ameren witness Jones stated, in the relevant part:

> Please see the attachment GER 1.16R Attach. As shown, the productive hourly wage rates for electric and gas metering employees range from approximately $195 to $171 per hour, respectively. The AIUs have proposed a similar charge in its gas tariffs. For ease of customer understanding, the AIUs proposed a uniform charge of $170 for both gas and electric service. The fee assumes that an average of about one hour of an employee's time that would otherwise be used for maintenance or new customer meter installation activities is instead consumed by time spent at a customer's location. (Staff Ex. 8.0, p. 6)

Therefore, in his direct testimony, Mr. Rukosuev recommended that Ameren amend its Standards and Qualifications for Electric Service tariff section to explicitly restrict application of its proposed $170 charge to non-residential customers only. Mr. Rukosuev also requested that the amended language be provided in Ameren's rebuttal testimony so that it could be reviewed and evaluated. (Staff Ex. 8.0, p. 7) Ameren agreed with Mr. Rukosuev's proposal. (Ameren Ex. 40.0R, pp. 19-20)

Furthermore, as stated above, referring to the Standards and Qualifications for Electric Service section, 2nd Revised Sheet No. 2.021 – Meter Reading, Ameren proposes a $170 fee for meter reads. In response to Staff DR GER 1.16R(e), which asked for an explanation of how the $170 fee for meter reads was calculated, Mr. Jones provided his response along with an attachment, GER 1.16R, which showed that the productive hourly wage rate for electric and gas metering employees range from approximately $195 to $170 per hour, respectively. (Staff Ex. 8.0, p. 7) In his direct testimony, Mr. Rukosuev stated that Ameren provided sufficient reasoning for the $170 fee in cases when a customer fails to provide access to an operating phone line. As stated by Mr. Rukosuev, "This fee is in fact below the productive hourly wage rates for electric and gas metering employees that range from approximately $195 to $171 per hour, respectively. The flat fee of $170 is reasonable and would effectively provide an incentive for customers to ensure they have operational phone lines for remote meter reading." (Staff Ex. 8.0, p. 8)

Staff witness Boggs also recommended approval of the following changes in Staff Ex. 10.0:

1. The Companies' proposal of the word additions/deletions and page updates in the Index subsection of the Companies' respective tariffs;

2. The Companies' proposal to eliminate certain sentences and phrases in the Service Extension paragraph including ones exclusive to Ameren IP;

3. The Companies' proposed language additions and deletions to the Interval Metering subsection paragraph;

4. The Companies' proposals to modify tariff language under section C of the Standards and Qualifications for Gas Service;

5. The Companies' proposal to charge customers who desire daily access to metered usage through USMS a one time fee of $1,944 when the Companies have to install an Electronic Pressure Corrector - Pulse Accumulator; and

6. The Companies' proposed $5.00 monthly fee assessment to customers for collecting the daily usage data by calling the modems at each meter from the USMS.

Rates DS-2, DS-3 & DS-4

Ameren proposed language changes to 4th Revised Sheet No.12.002 where the wording was changed to clarify that the AIUs' personnel could install unmetered services without first receiving a request from customers to do so. In 7th Revised Sheet No. 13, 6th Revised Sheet No. 13.001, 6th Revised Sheet No. 13.002, 7th Revised Sheet No.14, and 6th Revised Sheet No. 14.001, Ameren proposed language changes and sentence restructuring in order to clarify the difference between "Demand" and "Billing Demand" as discussed earlier, and other minor language and sentence changes to the last two paragraphs. (Ameren Ex. 40.0R, pp. 13-14) Therefore, in his direct testimony, Staff witness Rukosuev recommended approval of the proposed language changes because it improves the clarity across Ameren's tariffs without changing the substance of the current tariff language. (Staff Ex. 8.0, p. 13, 15)

Rate DS-5

Since some of its fixtures are no longer available, Ameren proposed language modifications to 4th Revised Sheet No.12.002. Ameren has illustrated with adequate reasoning that the proposed language changes are necessary in light of the circumstances. Therefore, in his direct testimony, Staff witness Rukosuev accepted Ameren's proposed language modifications. (Staff Ex. 8.0, p. 16)

Miscellaneous Fees and Charges

In his direct testimony, Staff witness Rukosuev accepted Ameren's proposed changes in the Miscellaneous Fees and Charges section, in the 2nd Revised Sheet No. 35.001. Mr. Rukosuev agreed that the proposed changes add clarity and helpful directional information. (Staff Ex. 8.0, p. 24)

In his direct testimony, Staff witness Boggs also accepted the establishment of a $170 non-scheduled meter read for customers in the GDS-4, GDS-6 and GDS-7 rate classes. (Staff Ex. 10.0, p. 27)

g. Supply Cost Adjustments for Rider PER

(1) Supply Procurement Adjustment – Rider PER

Staff witness Ebrey proposed that the total amount the AIU should be allowed to recover through the Supply Procurement Adjustment ("SPA") be set at $1,278,100 as set forth on Staff Ex. 1.0, Attachment B. (Staff Ex. 1.0, pp. 33-34) The AIU agreed with Staff's proposal. (Staff Ex. 15.0, p. 25)

(2) Uncollectibles Factor

Staff witness Ebrey proposed adjustments to the Uncollectibles Expenses proposed by the AIU since in her opinion, the use of estimated 2009 data did not meet the known and measurable criteria. (Staff Ex. 1.0, p. 27) In rebuttal, the AIU proposed to base its uncollectibles percentages on the 2007, 2008 and year to date 2009 actual data. (Ameren Ex. 29.0 (Revised), p. 10) Staff accepted this revised proposal. (Staff Ex. 15.0, p. 7) The AIU reflected those revised percentages for each utility in the calculations to develop the uncollectibles factors it proposes for the Supply Cost Adjustment. (Ameren Ex. 40.0 (2nd Revised), p. 18)

h. DS-4 Reactive Demand Charge

Staff witness Greg Rockrohr recommended that AIU modify language in each utility's Standards and Qualifications for Electric Service. Mr. Rockrohr believed that the existing language could give the false impression to Rate DS-4 customers that they can avoid monthly reactive demand charges if they maintain a power factor within the range 95% lagging to 95% leading. In actuality, based upon AIU's Rate DS-4 tariff, Rate DS-4 customers with a supply voltage below 100 kV cannot, in practical terms, avoid a monthly reactive demand charge. (Staff Ex. 11.0R, pp. 24-26) In response to Mr. Rockrohr's concerns, Ameren witness Leonard Jones proposed amended language for AIU's Standards and Qualifications for Electric Service that better explains reactive demand charges for Rate DS-4 customers. (Ameren Ex. 40.0 (2nd Revised), pp. 20-21) AIU's proposed amended language adequately addressed Mr. Rockrohr's concerns regarding AIU's reactive demand charges for Rate DS-4 customers. (Staff Ex. 24.0R, p. 12)

C. Contested Issues

1. Gas

a. Availability Tariff Provisions

b. Large Customer Rate for Non-CILCO GDS-4

In direct testimony, Staff misinterpreted Ameren's proposal to offer a rate provision for both AmerenCIPS and AmerenIP customers that use greater than 2 million therms annually. (Staff Ex. 9.0, p. 37) Ameren only proposed the large user rate under GDS-4 for AmerenCILCO due to the proposed elimination of GDS-6 for AmerenCILCO customers that use greater than two million therms per year. In rebuttal testimony, Staff stated that in this docket, a major focal point has been that Ameren has proposed a more common and uniform rate structure for all three gas utilities as directed in the Final Order, Docket Nos. 07-0585 - 07-0590 (Cons.). Offering the same provision for any customers using more than 2 million therms of gas annually conforms to the goals that Ameren has set in this case. (Staff Ex. 22.0, p. 3) Staff, in light of the fact that AmerenCIPS and AmerenIP have not assembled the necessary data to implement this change (Ameren Ex. 57.0, p. 2), recommended that Ameren should be ordered to assemble the relevant data for its next rate case. The data should enable Ameren to evaluate a similar rate design for large customers of AmerenCIPS and AmerenIP with usage of more than 2 million therms annually. (Staff Ex. 22.0, p. 5) In arriving at this recommendation, Staff considered the responses Ameren provided to Staff DRs (Staff Ex. 22.0, Attachment A), as well as the Company's direct testimony and proposed tariffs. Staff would not be injecting a level of complexity, as Mr. Millburg suggests in his rebuttal testimony. (Ameren Ex. 58.0 (2nd Revised), p. 9) Either the customers with over 2 million therms usage annually exist or they do not and these customers could exist in the future. If the customers exist or request service in the future, based on uniformity they should be offered the same rate regardless of the complexity of the rates Staff may inject. Staff is well aware of the initial reason that Ameren suggested this rate under GDS-4 so as to eliminate GDS-6 as Ms. Harden discussed in her direct testimony. Staff proposed that Ameren assemble the necessary data to further review this provision for AmerenCIPS and AmerenIP customers. Mr. Millburg acknowledges that this data may provide helpful information that could be useful in designing Ameren's gas tariffs in the next rate case. (Ameren Ex. 58.0 (2nd Revised), p. 9) Staff continues to recommend that Ameren should be ordered to assemble the relevant data for its next rate case.

c. Seasonal Prices for all GDS Rates

d. Transportation Tariff (Rider T)

Ameren provides transportation service to customers who desire to secure gas supply from a third party and to have that commodity delivered by the utility under Rider T – Transportation Service. These customers tend to be larger customers with commercial or industrial process load. By way of contrast, sales customers are primarily residential heating load customers. (Staff Ex. 27.0R, pp. 18-19)

(1) Unbundling Banking Rights

Under Rider T, Ameren provides a banking service whereby a transportation customer is given a bank equal to 10 times its MDCQ. The costs of these banks are recovered though the customers' base rates where they are bundled with distribution service. (Staff Ex. 14.0, p. 19) These costs are allocated based on peak day deliverability. (Staff Ex. 27.0R, p. 39)

Staff witness Sackett defines bundling as "the practice of a seller selling several services together for one price." Therefore, unbundling allows individual customers to buy only the services that they desire and at a level that best meets their needs. (Staff Ex. 14.0, p. 19)

Staff witness Sackett provides a comparison amongst major gas utilities regarding their respective bundling of banks for transportation customers:

> All other major gas utilities in Illinois currently offer banking to their transportation customers without bundling those services with base rates. Nicor Gas provides the largest banking service in terms of both total capacity and capacity per customer and it is unbundled from base rates.

> Peoples Gas and North Shore also provide banks that are unbundled from base rates for their larger customers. (*Id.*)

In fact, amongst these large utilities, only Ameren transportation customers are prevented from selecting a level of bank capacity that meets their individual needs. Additionally, other utilities allocate their seasonal capacity equitably to reflect their assets. (*Id.*, p. 20)

Staff proposes that the Rider T bank be unbundled from base rates and that the customer be allowed to subscribe to any level. This contrasts with providing a fixed amount of storage, i.e., ten days of the customer's MDCQ. (Staff Ex. 14.0, p. 19; Staff Ex. 27.0R, p. 6) Staff witness Mr. Sackett recommends that this occur in a three-part process:

1. Equitably allocate the Companies' storage assets;
2. Allow customers to select a bank level commensurate with their needs; and
3. Develop new charges to reflect appropriate costs.

He recommends that these changes be made in a workshop process with Staff and intervenors before the next rate case. Ameren should be required to propose tariffs that could be agreed upon in its next rate case. (*Id.*, pp. 6-7)

Ameren accepts this workshop process "in concept" and in part:

> The AIUs are not opposed to the concept. If structured properly, an unbundled Rider T bank would be an attractive customer-focused service offering. The customer would be the one to decide what level of bank to subscribe to based on the cost of the service instead of having to accept what level of bank service is negotiated by the parties participating in rate proceedings. The fundamental premise of unbundling any service is to allow the customer to choose the services it desires and the level of service desired. In order to make an informed decision or election, the customer should know the cost of the service upfront. (Ameren Ex. 64.0 (Revised), p. 12)

Ameren correctly identifies the value to the customer in choosing a bank level, but the phrase “if structured properly” has an uncertain meaning. Ameren may not agree with Staff about how to unbundle the Rider T bank in the workshop process.

Consequently, Ameren has objected to expanding the bank capacity stating it would create a subsidy from sales customers to transportation customers because capacity might not be available and if it is, it would be more expensive. (Ameren Ex. 44.0, pp. 22-23) However, Mr. Dothage indicated in the hearing that under his proposal, the individual customers’ capacity would not be limited to the current 10 times MDCQ. In fact, individual transportation customers are able to select any level of storage. (Tr., p. 847, December 17, 2009) This could lead to transportation customers as a group selecting more than their share of the assets. While Staff supports allowing a subscribable bank, the total should be limited to a proportional level of seasonal capacity. Therefore, Staff supports limiting the total capacity available to transportation customers as a group to that level determined as set forth below. This is the method that Nicor Gas uses to good effect and it necessarily protects sales customers.

Furthermore, Mr. Dothage states that he thinks it is reasonable to allow customers to select more than the current 10 day level “if they were willing to pay for that service.” (Tr., p. 847, December 17, 2009) Of course, if Ameren proposes a service that is overpriced, which could happen if it is based purely on off-system assets which tend to have a higher price, then this is not equitable. To set aside on-system assets for sales customers’ use only is just as unfair as to allocate no assets at all. (See the discussion below regarding the distinction between the operational treatment and the accounting treatment of these assets.) While Ameren appears ready to support a subscribable bank level, that is, a bank that allows customers to subscribe to a level of capacity, it provides no indication for how it would allocate resulting costs.

Therefore, Staff recommends that the Commission order that the unbundled Rider T bank be based on on-system storage assets (like Nicor Gas) or total system assets (like Peoples Gas) and not just on off-system assets. Staff also recommends that the size of the individual customer's allocation be constrained so that total transportation bank capacity be no greater than the level determined below.

(2) Size of Rider T Bank

To equitably allocate the assets between sales and transportation customers, we must first answer two questions that any allocation methodology must address: What assets will be divided? What measure (or allocator) should be used to allocate those assets? (Staff Ex. 27.0R, p. 18) Capacity allocation was addressed in the last Ameren rate case, Docket Nos. 07-0585 - 07-0590 (Cons.). This issue is about how to allocate seasonal capacity and is referred to here as the size of the Rider T bank. In the previous rate case, the Order states:

> The Commission agrees that banking service is appropriate for transportation customers. The Commission also recognizes that a reasonable size for a bank is related to other issues affecting utilities and transportation customers. Therefore, the Commission will take such issues into account when establishing a bank size for the three AIU gas operations. One factor to consider is the ease with which banking service can be implemented. Obviously, a uniform bank size among all three utilities facilitates implementation. What also facilitates implementation and use is measuring a bank size in units already in use. As discussed above, Nicor currently calculates bank size using MDCQ, as does AmerenIP under Rider OT. The fact that a customer's MDCQ will generally be known well in advance facilitates banking as well. Overall, the Commission finds that measuring a bank size through a customer's MDCQ to be reasonable and consistent with prior decisions...
> With regard to the size of the bank, the proposals vary. AIU primarily argues that resources are simply not available to offer "large" banks. AIU also expresses concerns about gaming by transportation customers.

> While gaming probably occurs to some extent, the Commission is not convinced by AIU's evidence that gaming is as widespread of a problem as AIU suggests, and therefore the potential for gaming need not be considered in setting bank size and related issues. The Commission accepts, however, that AIU has less capacity for banking than Nicor, Peoples, and North Shore. In light of the conclusions below, the Commission finds that a 10-day MDCQ bank is an appropriate size. (Order, Docket Nos. 07-0585 - 07-0590 (Cons.), September 24, 2008, pp. 312-313)

The Commission links the ability to provide banking services to the storage capacity of the utility. Because all three Ameren LDCs offer the same size bank even though each LDC has unique storage portfolios, this link is not reflected in the10-day bank capacity provided to Ameren transportation customers. Staff recommends that the Commission reconsider this finding as "there are many rate case determinations that relate to the relative differences of the system such as the charges that AIU proposes to be unique to each utility. Bank capacity should be treated the same." A similar case exists for Peoples Gas and North Shore which have the same parent company, but have different storage assets and different levels of bank approved by the Commission. (Staff Ex. 14.0, p. 21)

Staff witness Sackett provides a relevant comparison by using the seasonal capacity allocation methods of Nicor Gas and Peoples Gas to show that the proportional capacity is very similar. He provides these calculations in Table 4 of his direct testimony. (*Id.*, p. 24) These calculations show that Ameren's total system capacities, relative to peak day needs, are comparable to the other utilities. This evidence shows that, while Ameren has less capacity in an absolute sense than Nicor Gas, Peoples Gas and North Shore, a similar allocation method, would yield banks significantly larger than the current level. Furthermore, Peoples Gas, which has just a single on-system storage field, and North Shore, which has no on-system storage, both offer relatively large banks when compared to Ameren despite the fact that Ameren has numerous on-system storage fields that provide more flexibility. (*Id.*, pp. 21-22)

The size of the Rider T bank is determined by how the seasonal capacity is allocated. Ameren's positions in the last rate case were rejected, and these same objections are offered up in this case. In the prior rate case, Ameren proposed to eliminate all banks for transportation customers. Ameren's witness in this case uses the same arguments to advance new positions and his arguments should be evaluated in the context that in which they were originally advanced. Ameren continues to resist a *right* to any allocation of storage, equitable or otherwise. (Staff Ex. 27.0R, p. 8) Staff believes that the evidence in this case supports a result different from the conclusion reached by the Commission in the last case. (*Id.*, pp. 9-10)

The Commission adopted Staff's position in Ameren's last rate case. (Order, Docket Nos. 07-0585 - 07-0590 (Cons.), September 24, 2008, p. 313) The Commission's decision on bank size was based on Staff's recommendation which was "a compromise between the 12 times MDCQ currently available to AmerenIP Rider OT customers and the 10 times [Average Day Peak Month] currently available for Rider T banks at AmerenCILCO and AmerenCIPS." (*Id*., pp. 299-300)[71] However, these historic bank levels were not based on an equitable allocation of storage capacity. (Staff Ex. 27.0R, p. 17)

Staff witness Sackett explained that the reason he did not propose an equitable allocation of seasonal capacity was due to the across-the-board rate increase supported by Staff. (*Id.*)

[71] It was also the middle-ground position between the 8-days that Ameren proposed (Order, Docket Nos. 07-0585 - 07-0590 (Cons.), September 24, 2008, p. 297) and the 12-13.5 day position advocated by CNE. (*Id.*, p. 308)

Mr. Sackett notes in rebuttal that "Ameren never provides any evidence that its current allocation of 10 days of a transportation customer's MDCQ for a maximum bank level is equitable." (*Id.*, p. 8)

Mr. Dothage responds in surrebuttal that Ameren increased its bank levels and concludes that "the existing 10 day bank allocation to transportation customers is extremely fair and equitable." (Ameren Ex.64.0 (Revised), p. 19) However his rhetoric relies on the fact of that Ameren has *increased* its banks. He takes the position that the new 10-day banks (which Ameren opposed in the last case) are "*extremely* fair and equitable" because transportation customer banks have increased significantly since the last case. However, these results occurred due to the regulatory change and the customer migration from sales to transportation since the last rate case. It is interesting that Mr. Dothage uses migration to support his claim of fairness and equitability because bank levels more than doubled the bank levels since the last rate case. (Ameren Ex. 64.0 (Revised), p. 19) Staff agrees that allocations are *more* equitable, a conclusion that seems reasonable to draw, but is left unstated by Ameren. Mr. Dothage's conclusion also begs the question: if such an increase made things fair and equitable, would a further increase not make it *more* fair and equitable? The answer depends on whether we have yet arrived at a fair and equitable allocation. The increase ordered in that last rate case was a good step in the right direction (albeit the opposite direction from that originally proposed by Ameren).

Mr. Dothage lists three objections to Staff's proposal: that there is no demand for unbundling the Rider T bank, that it is too soon to consider changing the current tariffs, and that it will result in an allocation away from sales customers to transportation customers. (Ameren Ex. 44.0, p. 17) He provides further information that obscures the facts surrounding customer migration from sales service to transportation service (Ameren Ex. 64.0 (Revised), pp. 23-24) and off-system storage availability (*Id.*, p. 25). His information does not enlighten. However, after the dust has cleared on each of these issues, it is clear that the evidence supports Staff's proposal.

Transportation customers want equitable storage allocation.

Ameren witness Dothage objects to Staff's proposal to unbundle the Rider T bank because he maintains that "transportation customers are not interested in unbundling the balancing service" because no one has asked for any changes to the tariff. (Ameren Ex. 44.0, p. 17) By this, he means that no transportation intervenor raised this issue in direct testimony. (Ameren Ex. 64.0 (Revised), p. 25) Of course, just because no intervenor chose to raise this issue in direct testimony is not proof that they do *not* support these concepts. Historical evidence and discovery in this docket proves that transportation intervenors support Staff's position in this issue.

Mr. Dothage fails to provide any support for his conclusion that transportation customers are not interested in the service. On the other hand, Staff witness Sackett concludes that, based upon other rate proceedings, transportation customers support an unbundled storage option.[72] (Staff Ex. 27.0R, p. 10)

Moreover, in Ameren's last rate case, CNE asked the Commission to allocate storage capacity using either the Nicor Gas or Peoples Gas method:

> Regardless of the Commission's decision regarding storage allocation, CNE-Gas recommends that AIU be required to investigate the storage allocation methodologies of both Peoples and Nicor. The Commission, CNE-Gas continues, should order AIU to work with Staff and interested stakeholders to study the impact of utilizing these other storage allocation methodologies in order to more equitably allocate storage assets between

[72] IIEC, Vanguard and CNE all supported an unbundled storage bank in Docket Nos. 07-0241/0242 (Cons.). (Order, Docket Nos. 07-0241/0242 (Cons.), February 5, 2008, pp. 279-280)

> sales and transportation customers in the future. (Order, Docket Nos. 07-0585 - 07-0590 (Cons.), September 24, 2008, p. 308)

CNE renews its support in the instant case. CNE witness Kawczynski states in his rebuttal, "Let me assure the Commission that CNE-Gas is interested in unbundling." (CNE Ex. 2.0, p. 19)

Staff also conducted discovery of transportation intervenors in this case. In its responses to Staff DRs DAS 8.1-8.3, CNE states that it generally supports allocating storage assets using the methodologies the Commission approved for Nicor Gas and Peoples Gas, which unbundle banks from base rates, allow transportation customers to select a level of banking they need, and ties cost recovery to the selected bank level. (Staff Ex. 27.0R, p. 12) In addition, the IIEC, another transportation intervenor, states that its member companies would "likely" be supportive of these same issues in its responses to Staff DRs DAS 9.1-9.3. (*Id.)*

<u>Ameren has had sufficient time to recognize the inequity and correct it.</u>

Mr. Dothage states that the current banking provisions have only been in effect for less than a year, and there is not enough experience to support a change at this time. (Ameren Ex. 44.0, p. 17) However, he cited no problems with the current tariff provision. Since Ameren is actually reducing its off-system storage capacity, the current system appears to be functional. (Staff Ex. 27.0R, p. 13) This indicates that Ameren has not had a difficult time supplying the increased bank capacity provided in the Commission's order in the previous rate case.

<u>Staff's proposal to allocate storage capacity equitably does not create a subsidy; it corrects one.</u>

Mr. Dothage objects to Staff's proposal by claiming that it will cause a reallocation of storage assets and create a subsidy from sales to transportation customers. (Ameren Ex. 44.0, pp. 17, 23) On the other hand, Mr. Sackett concludes that there is an *inequity*[73] in the current banks afforded to Ameren's transportation customers. (Staff Ex. 14.0, pp. 22-24) Since an inequity becomes a *subsidy*[74] when the cost to the sales customers is less than it would be if transportation customers were receiving an equitable share of the assets, Staff believes that there is a subsidy in this case as well. Mr. Sackett's proposal corrects the inequity that occurs when a customer must give up storage when switching to transportation service as transportation customers receive too little storage. Correcting this allocation addresses the current subsidy. (Staff Ex. 27.0R, pp. 29-30)

Staff witness Sackett discusses the efficiency loss that occurs when transportation customers are allocated less than an equitable portion of the storage assets. "Sales customers benefit from storage assets both in terms of meeting peak day requirements as well as seasonal hedging *regardless of their size*. If a sales customer loses all or part of that benefit when they switch to transportation service, they will be unduly deterred from transportation service." (Staff Ex. 27.0R, p. 30) He concludes that since both transportation and sales customers are customers, they should have equal access to the utility's assets. He further notes that the Commission has supported this concept in the previous Ameren rate case as well as every Peoples Gas and Nicor Gas rate case for the last 14 years. (*Id.*)

Mr. Dothage claims that *on-system* assets are needed to serve the needs of sales customers. "Between 29% and 45% of the AIUs' *on-system* storage capacity

[73] Mr. Sackett defines an inequity as where the capacity allocated to one party is not proportional compared to the other parties. The proportionality must reflect consideration of at least one characteristic of all parties. (Staff Ex. 27.0R, p. 29)
[74] Mr. Sackett defines a subsidy as the result of an inequity where the costs to one party are lower because they are partially paid for by another. (*Id.*)

would be required to support Mr. Sackett's proposed expansion of the Rider T banks. This would represent a massive shift in *on-system* storage resources that are utilized to support sales service today to transportation customers to support banking rights." (Ameren Ex.64.0 (Revised), p. 17, emphasis added) Mr. Dothage obscures that fact that, while for accounting purposes (to recover the costs) these banks are treated as though they to are put in on-system assets, for operational purposes, there is no direct connection between the gas delivered and the actual assets used to store that gas. If it is Mr. Dothage's testimony that those assets are exclusively used to support sales customers (as his testimony implies), then Ameren recovers storage costs from transportation customers for precisely those same assets which, according to him, those customers do not use.

It is irrelevant where Ameren directs banked gas. It could be stored in on-system underground storage fields or off-system storage assets. Furthermore, there is no expectation that the exact same gas is withdrawn when the customer makes a withdrawal. Staff's proposal will not require that any more of these valuable balancing assets are, in an operational sense, are dedicated to transportation customers' injections or withdrawals than before.

<u>The Peoples Gas and Nicor Gas methods are reasonable for their purpose.</u>

Ameren transportation customers pay only on–system storage costs (like Nicor Gas) but receive banks that do not reflect the relative allocation of the cost of the storage assets of each LDC. (Staff Ex. 14.0, p. 22)

Asset allocation methods employed by the other large utilities in Illinois have much in common with each other. They all allocate a proportional share of those assets for which transportation customers are paying. Specifically, Peoples Gas and North

Shore each use a method that allocates the *total* system storage capacity (on- and off-system) divided by system deliverability on a peak day. Staff witness Sackett conducted a comparative analysis and found that if Ameren were to allocate its storage using the Commission-approved method used by Peoples Gas and North Shore, transportation customers' allocation would be 37, 35, and 27 days of MDCQ for AmerenCILCO, AmerenCIPS and AmerenIP, respectively. (*Id.*, pp. 22-23)

Nicor Gas allocates total *on-system* storage capacity divided by the peak design day demand. Mr. Sackett also determined that if Ameren were to allocate its storage using the Commission-approved method used by Nicor Gas, transportation customers' allocation would be 24, 11, and 24 days of MDCQ for AmerenCILCO, AmerenCIPS and AmerenIP, respectively. (*Id.*)

Using either of these allocation methods significantly increases the bank capacity for transportation customers.[75] (*Id.*, p. 23)

Mr. Dothage objects to the result of this calculation saying it lacks an operational meaning. (Ameren Ex. 44.0, pp. 21-22; Ameren Ex. 64.0 (Revised), pp. 15-16) However, he acknowledges that Staff, the Commission and other utilities use these methods and do not attempt to assign an operational meaning to the result of this calculation. (Tr., pp. 834-836, December 17, 2009) Mr. Dothage claims that that the "Peoples Gas/North Shore Model and the Nicor Gas Model are not viable, reasonable models for use by the AIU." (Ameren Ex.64.0 (Revised), p. 26) This would suggest that Ameren is materially different than Nicor Gas or Peoples Gas. However, Ameren presented no evidence showing that its LDCs do not have one or more of the inputs into either method. The only other implication from this is that Mr. Dothage considers the

[75] The lone exception is AmerenCILCO using Nicor Gas' method which would only increase by 1 day.

methods themselves defective in their current use in both Nicor Gas and Peoples Gas because the same defect must certainly exist there. The results, which provide the days of bank in both cases, do not have any "rational meaning in the real world of physical deliverability and capacity." (Ameren Ex. 44.0, p. 22) According to Mr. Dothage's logic, these methods must be equally defective and the Commission and Staff must be remiss in supporting their usage to allocate seasonal capacity between sales and transportation customers:

> The purpose I believe is to come up with, to purport to come up with a number of days for transportation customers' bank entitlements. That's what the models have been used for previously.
> …
> The purpose of the Nicor model is to purportedly come up with the number of days, mathematically determine the number of days that a transportation customer is entitled to banking service.
> …
> The Commission has determined in the past to use the number of days that results from the product to determine how many days of bank service transportation customers are entitled to.
> (Tr., pp. 834-836, December 17, 2009)
> X X X X X X X X X X X X X X X X X X X X X X X X X X X X X X X X X X X X X X

X Mr. Dothage shows how unfamiliar he is with the methods, because despite his acknowledgement that no one uses these results for any purpose other than seasonal capacity allocation for transportation customers, he still tries to impose operational significance on these results. This is something that Staff did not propose or even suggest, and something that the Commission does not do.

Mr. Dothage is not very familiar with the methodologies. He apparently does realize that the Commission uses these methods to determine bank capacity entitlements, but attempts to convolute some operational meaning to the result of the entitlement calculation. Of course there is no operational meaning to this calculation. This fact does not make the calculation invalid even if it falls outside Mr. Dothage's comprehension. His (limited) understanding is not the litmus test. Peoples Gas, Nicor Gas, Staff and the Commission all understand the purpose of these methods and the logic behind why such a calculation makes sense. In fact, these methods have not even been contested in other gas utilities' rate proceedings.

Mr. Dothage rejects the models that Mr. Sackett used to show each LDC's relative assets. (Ameren Ex. 44.0, pp. 21-22) These "models" (or methodologies) (see Staff Ex.14.0, p. 22-24) were considered and previously accepted by the Commission. (Order, Docket No. 95-0031, November 8, 1995, pp. 56-58; Order, Docket No. 95-0032, November 8, 1995, pp. 69-71; and Order, Docket No. 95-0219, April 3, 1996, pp. 60-62).

As was stated at the beginning of Section VII.C.1.d.(2) above, to equitably allocate the assets between sales and transportation customers, we must first answer two questions that any allocation methodology must address: What assets will be divided? What measure (or allocator) should be used to allocate those assets? (Staff Ex. 27.0R, p. 18)

The Commission answers the first question by using total on-system assets in Nicor Gas and total system assets in Peoples Gas and North Shore. (Staff Ex. 14.0, p. 22)

The Commission answers the second question by allocating a proportional slice to the individual transportation customers using peak day supply in Peoples Gas and North Shore (Order, Docket No. 95-0031, November 8, 1995, pp. 56-57; and Order, Docket No. 95-0032, November 8, 1995, p. 69) and peak day demand in Nicor Gas (Order, Docket No. 04-0779, September 20, 2005, p. 117). Staff witness Sackett has concluded that these methods are roughly equivalent, well-established and reasonable. (Staff Ex. 27.0R, pp. 18, 20)

A peak day allocator favors sales customers. Smaller customers generally have usage that is largely influenced by heating load and is therefore more weather sensitive. Thus, they represent a relatively larger portion of peak day demand relative to annual usage than transportation customers who tend to include larger process load customers. Therefore, transportation customers' share of annual use is greater than their share of peak day use. (*Id.*, pp. 18-19) If capacity is allocated to individual customers based on their peak day usage (or MDCQ) or the "days of bank" and allocate underground storage costs based on peak day deliverability, then it makes sense to divide the seasonal bank capacity into peak days. (*Id.*, p. 39)

While Mr. Dothage objects to using a peak day allocator and claims that the annual capacity and peak day demand are not related (Ameren Ex. 44.0, p. 22), Ameren witness Normand uses a peak day allocator to allocate annual underground storage costs to transportation customers (Ameren Ex. 16.8).

Mr. Dothage insinuates that the natural result of the Nicor Gas method is a fixed level of bank capacity for each transportation customer. (Ameren Ex.64.0 (Revised), p. 19) However, he notes that Nicor Gas uses the method but also has incorporated subscribability in its Unbundled Storage Bank. (Tr., p. 847, December 17, 2009)

Facts contradict Ameren predictions.

Mr. Dothage states that unbundling the bank will have two potentially disastrous effects. First, there may not be sufficient additional off-system storage available to accommodate the larger banks. Second, any off-system storage that is available will likely be at a higher cost than existing assets. (Ameren Ex. 44.0, p. 23)

This is similar to the claims that Ameren made in the previous rate case which did not come to pass. In the previous rate case, Ameren witness Glaeser claimed that "the Ameren Illinois Utilities currently require all of their storage resources and related deliverability to meet their sales customer's peak day demand. The Ameren Illinois Utilities have no excess storage capacity available to provide a new open access storage service." (Docket Nos. 07-0585 - 0590 (Cons.), Ameren Ex. 30.0, p. 26)

However, there are four pieces of evidence that show that this claim did not come to fruition since the last case:

1. Migration of customers from sales to transportation service reduces Ameren's peak day or seasonal storage requirements.

Taken alone without any migration, Staff's proposal to allocate seasonal storage capacity on the basis of share of peak day usage will not increase Ameren's peak day requirements, that is, the amount of gas that Ameren is responsible for supplying. This is because these requirements are independent of the size of the banks (seasonal storage capacity). (Staff Ex. 27.0R, p. 23) When you factor in the migration of customers from transportation service to transportation service, Ameren' peak day requirements *decrease*. The reason for the decrease is that transportation customers must deliver most of their peak day usage from the interstate pipelines, getting the remainder of their needs from their banks using Ameren's storage resources. In contrast, a sales customer receives his entire supply from Ameren either through Ameren's deliveries into its systems or from on system storage assets.

Net migration is overwhelmingly from sales service to transportation service.

Mr. Dothage raises questions about the direction of migration by implying that there has been some migration in the other direction. He states that Mr. Sackett "conveniently fails to acknowledge or is unaware of the fact that the AIUs also have had transportation customers elect to switch to sales service," and accuses Mr. Sackett's forecast of continued migration as "pure speculation." (Ameren Ex. 64.0 (Revised), p. 23)

There had not been limited movement to sales service but the overall trend is clearly toward transportation service. Mr. Dothage offered no data to support his worries. Staff provided the data in Staff Group Ex. 1-X, Y & GG. In fact, Mr. Dothage admits in the hearing that he based his claim on only one instance of movement to sales service, which resulted from the elimination of a unique transportation service.[76] This shift did not overcome the predominant shift from sales service to transportation service. (Staff Group Ex. 1-X, Y & GG) Since the last case, no transportation customers moved from Rider T to Rider S. It seems very likely that Staff's proposals will make transportation more attractive to customers and that net migration to transportation service will continue. (Staff Exhibit. 27.0R, p. 27) Staff is now "aware" and "conveniently acknowledges" the fact that customers have at one time under unique circumstances

[76] "AIU proposes to eliminate Rider OT--Optional Transportation of Customer-Owned Gas from AmerenIP's tariff books. AIU indicates that this rider allows customers essentially to switch back and forth between system sales gas and transportation service." (Order, Docket Nos. 07-0585 - 07-0590 (Cons.), September 24, 2008, p. 315)

moved from transportation service to sales service. However, Staff still draws the same conclusion and makes the same recommendations to the Commission.

When asked if migration from sales to transportation services would “cause Ameren's peak day requirements to increase, decrease, or remain the same,” Mr. Normand concluded, “Our peak day requirements for the system would stay the same because whether that customer is a transportation customer or a sales customer, the assumption is they'll be transporting or buying or using the same amount of gas. I think you were just talking about a customer changing from sales service to transportation service, so our peak day throughput would remain the same.” (Tr., pp. 820-821, December 17, 2009) However, Mr. Normand’s “peak day requirements” is referring to the amount of gas that Ameren is delivering, as is clear from his next answer where Mr. Dothage admits that Ameren is “responsible on a peak day for all of the sales customers requirements” but that “transportation customers are expected to source their own gas and bring that to the system. They do have a right to a 20 percent banking withdrawal on a peak day.” (Tr., p. 821, December 17, 2009) Therefore, since the transportation customers must buy gas and deliver it to Ameren’s system and Ameren has only to provide bank withdrawals, the portion of peak day gas that Ameren provides does decrease as customers move to transportation. Ameren’s portion of the peak day requirements must go down. The total amount of gas that Ameren must supply on a peak day decreases as sales customers switch to transportation and must supply a portion of their needs themselves.

Therefore, as customers migrate to transportation service, Ameren can reduce the amount of storage needed to support peak day requirements. As transportation service becomes more economical, migration will only continue. To the extent that

Staff's proposals will cause continued migration to transportation service, all other things being equal, will reduce the amount of gas Ameren procure itself or bring out of its system storage. (Staff Ex. 27.0R, p. 23)

This is also the case with Ameren's seasonal requirements. Mr. Dothage admits that "Ameren is responsible for all of the sales customers' seasonal load and only has an obligation for bank withdrawals for the transportation customers on a seasonal basis." (Tr., p. 821, December 17, 2009) Since the bank withdrawals cannot equal the seasonal usage and Ameren has only to provide bank withdrawals, Ameren's seasonal requirements must go also go down.

2. <u>The storage portfolio evidence contradicts Ameren predictions.</u>

Ameren warned that it would have to buy additional storage to support larger banks. However, Ameren's own actions directly contradict what it predicted in that case. It could have purchased additional storage to fulfill its own predictions, but it did not even attempt to do so. (See Staff Ex. 27.0R, Attachment C)

The Commission ordered a bank expansion for each LDC in the last rate case order. For both AmerenCILCO and AmerenCIPS, the Commission ordered the bank increased from 10 times the average day of the peak month ("ADPM") from the previous 12 months to 10 times MDCQ, which results in a slightly bigger bank. (Staff Ex. 27.0R, p. 24)

However, for AmerenIP, the Commission ordered that banks be provided to all transportation customers. According to Ameren Response to Staff DR DAS 1.26, the storage capacity devoted to transportation customers increased from 467,755 MMBTU to 2,592,675 MMBTU as a result of expanding the banks in 2007, an increase of over 450%. (*Id*., pp. 24-25) Therefore, AmerenIP is a good model for this case, because it had the largest increases of the three LDCs since the last case. (*Id.*) However, according to Ameren witness Seckler, since the transportation provisions from the last rate case went into effect (less than a year ago), the only change in AmerenIP's off-system storage was a *reduction* of 15% in its Mississippi River Transmission ("MRT") storage contract level. (Ameren Ex. 45.0 (Revised), p. 12)

In fact, the same is true for each LDC that has increased capacity allocated to transportation customers according to Ameren's Responses to Staff DRs DAS 1.26 and DAS 11.06 (Staff Ex. 27.0R, pp. 25-26), but Ameren has *reduced* off-system storage capacity (Ameren Ex. 45.0 (Revised), pp. 11-12). This is exactly the opposite of Ameren's prediction. Ms. Seckler's testimony contradicts Mr. Dothage's prediction of "major risk and harm" and, thus, undermines his position. (Staff Ex. 27.0R, p. 26)

Mr. Dothage attempts to divert attention from Ameren's releases of storage capacity by providing evidence of the lack of pipeline storage capacity at the time of his surrebuttal testimony. He states that four of the pipelines that serve Ameren do not currently have pipeline storage available and therefore that "the AIUs cannot simply go to the marketplace to add storage whenever they want". (Ameren Ex. 64.0 (Revised), p. 25)

However Mr. Dothage's testimony is misleading because he acknowledges that the multi-year contracts that Ameren enters into are reconsidered at the beginning of the injection season, not during the withdrawal season (or "whenever they want"), that other LDCs also are making these changes in the spring and that he is not surprised to find that capacity unavailable at this time. (Tr., pp. 848-854, December 17, 2009) Finally, there are other pipelines from which Ameren receives storage services. (Ameren Exhibit. 44.4 Confidential) Mr. Dothage takes his snapshot at the wrong time (not during the time when the actual changes would be made) and then only provides a partial snapshot. His evidence does not support his conclusion.

3. <u>Ameren's "strategy" contradicts Mr. Dothage's predictions.</u>

It seems counterintuitive that after banks were expanded and large numbers of customers migrated to transportation service after 2007 that Ameren would release off-system capacity.

However, this occurred because it fit Ameren's "strategy," in which it planned "to have approximately 50% of its normal winter requirements met by storage withdrawals." (Staff Ex. 27.0R, Attachment B) These normal winter requirements are for sales customers' usage and transportation customers' withdrawals from banks. Because Ameren only has to supply withdrawals from bank, which at the most could be 20% of usage for GDS-4 customers and 50% of usage for GDS-2 and 3 customers, normal winter *requirements* will go down. (Tr., p. 822, December 17, 2009) Furthermore, unless Ameren changes its strategy, it will continue to shed pipeline capacity in the future.

Mr. Dothage claims that "even if [off-system capacity] is available, the capacity likely would be at a much higher cost than the existing storage capacity." (Ameren Ex. 44.0, p. 23) However, once again, Ameren is mischaracterizing the situation. Due to Ameren's capacity strategy, the *price* of storage capacity becomes irrelevant as migration to transportation continues. Moreover, the release of capacity that has occurred since the 2007 rate case has *reduced* the off-system costs to sales customers, contradicting Mr. Glaeser's prediction from the last rate case. [77] Ameren's actions

[77] Mr. Glaeser claimed in the previous rate case that "if the Ameren Illinois Utilities were ordered to offer a storage service to the transportation customer class, *additional leased storage resources would have to be secured* by the respective Ameren Illinois Utility and would most assuredly be at *a higher cost than the*

discredited Mr. Glaeser's claim from the last case, and so Mr. Dothage's identical claim in this case should, therefore, be given no credence. (Staff Ex. 27.0R, pp. 27-29)

4. Ameren's unlimited bank contradicts Mr. Dothage's objections.

Mr. Dothage has warned of major risk and harm because he feels Staff's proposal would shift assets away from sales customers and create a subsidy from sales customers to transportation customers. (Ameren Ex. 44.0, pp. 22-23)

However, Mr. Dothage contradicted his own objections when he indicated in the hearing that under his proposal, the individual customers' capacity would not be limited to the current 10 times MDCQ. In fact, individual transportation customers are able to select any level of storage. (Tr., p. 847, December 17, 2009) This could lead to transportation customers as a group selecting more than 10 times MDCQ as a group, which could result in the same increased capacity allocation proposed by Staff. Having warned of impending doom, Mr. Normand cannot be taken seriously since his own recommendation could have the same or worse effects.

In fact, Mr. Normand's limitless subscribable bank may even cause transportation customers as a group to select more than their equitable share of capacity as proposed by Staff. While Staff supports allowing a subscribable bank, the total should be limited to a proportional level of seasonal capacity. Therefore, Staff supports limiting the total capacity available to transportation customers as a group to that level determined as set forth below. This is the method that Nicor Gas uses to good effect and it necessarily protects sales customers.

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current gas supply resources which the sales customers pay through the PGA rate mechanism. In other words, costs would go up for the sales customers." (Docket Nos. 07-0585 - 0590 (Cons.), Ameren Ex. 30.0, pp. 26-27) (emphasis added)

In summary, Staff recommends that the Commission require Ameren to work with Staff and Intervenors to develop an equitable allocation process for storage assets, to allow customers to select the level of banking that best suits their needs, and to develop an equitable allocation of the costs of providing those services. Ameren should be required to propose these changes in its next rate case. (Staff Ex. 27.0R, p. 31)

e. Other

2. Electric

a. Rate Moderation/Mitigation Approaches

The Staff-proposed allocation of revenues among rate classes should be adopted in this proceeding. The proposed approach is simple, straightforward and consistent for all rate classes on the AIU systems. It would allocate revenues according to their underlying costs subject to the limitation that no class would receive an increase greater than 150 percent of the system average increase. Thus, Staff appropriately balances costs and bill impacts concerns in allocating revenues among rate classes.

The alternative revenue allocations proposed by the AIUs are contradictory and confusing. The AIUs ostensibly seek to limit increases for any individual class to 125% of the system average increase to address bill impacts. However, the Company proposal excludes distribution taxes from the constraint and thereby produces much larger increases for individual classes. (Staff Ex. 7.0, p. 14)

The AIUs advocate a constrained increase because of the difficulties ratepayers have encountered in recent years adjusting to electric rate increases. AIU witness Jones references the problems certain ratepayers encountered in adjusting to the end of the rate freeze in January 2007, which required the Commission to initiate a “rate redesign docket” to address “severe customer impacts.” Mr. Jones notes that this docket produced further adjustments to both DS and BGS rates that became effective in December 2007 and January 2008. He goes on to indicate that continuing bill impacts concerns in the Companies' most recent delivery service rate case led to across-the-board increases on existing rate elements (effective October 2008) to avoid disproportionate increases for customers. Mr. Jones states that rates approved in this case will become effective in May 2010, which is two and a half years after the rate redesign docket's order and three and a half years after the rate freeze was replaced by auction-based rates. Given this timeframe, Mr. Jones finds it appropriate to resume "making steps toward cost-based rates, while helping to minimize the potential for disproportionate bill impacts to customers." (Ameren Ex. 16.0E (2nd Revised), pp. 10-11)

The problem for Mr. Jones is that the constraint he has chosen does not cover costs associated with the distribution tax. The assumption underlying this contradictory approach is that ratepayers are concerned about bill impacts caused by some costs but not others. The Companies appear to believe that ratepayers will accept disproportionate increases as long as they are tied to PURA taxes. However, there is no evidence on the record to indicate that customers make such a distinction. Furthermore, the Companies' discriminatory approach to bill impacts concerns defies logic which would indicate that ratepayers care about all components of their electric bills including distribution taxes. (Staff Ex. 7.0, pp. 16-17)

The second problem centers on the Companies' unequal treatment of DS-5 lighting customers. The Companies propose significantly higher revenues for the lighting classes than justified by the underlying cost. The AIUs base this proposal on the ostensible objective of making lighting charges more uniform across the Companies. (Ameren Ex. 16.0E (Revised), p. 7) AIU witness Jones indicates that "[t]he result of the

DS-5 revenue allocation methodology is revenue reductions of approximately $1.97 million, $1.62 million, and $60,000 reallocated to each respective AIUs' DS-1 through DS-4 classes." (Ameren Ex. 16.0E (Revised), pp. 7-8)

This allocation is unfair to lighting customers who receive a higher increase than justified by the methodology applied to other rate classes. The AIUs appear to believe that lighting customers can afford to pay a higher share of the cost of service than other customer classes. It should be remembered that lighting bills are paid by municipalities that, in turn, must recover the costs from taxpayers. If lighting rates go up, the higher costs will be borne by taxpayers. The more equitable alternative is to apply the same revenue allocation rules to all rate classes. (Staff Ex. 7.0, pp. 17-18)

The Companies also contend that these higher revenue allocations are necessary to make progress toward the ratemaking goal of equalizing lighting rates. That argument should be rejected as well. It is true that in Docket Nos. 07-0585 et al. (Cons.), the Commission Order directed the AIUs "to address the possibility of moving the light fixture charges toward a more similar charge among AmerenCILCO, AmerenCIPS, and AmerenIP." (Order, September 24, 2008, p. 359) However, addressing a possibility of moving to similar charges is far different from making it a requirement and in any case the Commission is not suggesting that lighting customers should be allocated higher revenues as a result. (Staff Ex. 7.0, p. 18)

A final problem is that the Companies' proposed class revenue allocations rest upon a flawed cost of service foundation that features an NCP allocator for primary distribution lines and substations. To the extent that the cost studies deviate from cost causation principles due to this error, that will distort the resulting class revenue allocations regardless of the methodology employed. (*Id.*, p. 18)

The Commission should instead adopt the class revenue allocations proposed by Staff. These revenue allocations differ from the AIU's proposal in two key respects. For one, the Staff alternative revenue applies a consistent revenue constraint on all current base revenues including distribution taxes for all customer classes including the Lighting class. The specific proposal is to limit the increase on current rates for any rate class to 150% of the system average increase approved in this proceeding under the Companies' proposed revenue requirement. Second, they are based on a cost of service study that appropriately incorporates a CP, rather than a NCP, allocator for primary lines and substations. (*Id.*, p. 19)

Staff, like the other parties to this case, is concerned about bill impacts for AIU ratepayers. The need to constrain class revenue increases recognizes that bill impacts are a major concern to customers and the Commission. However, bill impacts are not the only concern in allocating the revenue requirement. Costs are important as well. The Commission has a longstanding principle of basing rates on costs which it reaffirmed in the Companies' most recent case by stating that it "finds value in Staff's recommendation that AIU provide gas and electric rates in the next rate cases based on cost of service and directs AIU to do so in the next rate cases." (Order, Docket Nos. 07-0585 et al. (Cons.), September 24, 2008, p. 281)

The best way to balance these two concerns is through a constrained class revenue allocation. However, any effort to address bill impacts in the revenue allocation process must be consistent and fair to all rate classes. The Staff proposal meets this test while the Companies' proposal does not.

Staff's proposed 150% constraint represents a reasoned judgment of how much progress can be made towards cost-based revenue allocations while addressing bill impacts concerns. While the Staff constraint is higher than the Company proposal, 150% vs. 125%, it encompasses all costs in the revenue requirement while the AIU proposal exempts PURA taxes. Thus, the Staff proposal is more consistent and equitable. (Staff Ex. 7.0, p. 22)

Staff's approach accords the largest percentage increases to the biggest customers on the system. This result is largely driven by the reallocation of costs associated with distribution taxes among rate classes. The shift in allocation of distribution taxes from utility plant to usage shifts responsibility for these costs to DS-3 and DS-4 customers who account for 12% and 43% of sales, respectively. (Ameren Ex. 16.0E (2^{nd} Revised), p. 8)

Despite this shift, the Staff-proposed increases for these customers will not produce an undue increase in their overall cost of electricity. Utility bills for large customers generally extend to delivery service costs only because they tend to purchase power from non-utility suppliers. Thus, a significant increase in delivery services does not necessarily translate into a large increase in the overall cost of electricity. This is illustrated by an example provided by AIU witness Jones of a hypothetical large DS-4 customer taking delivery service from the Companies under present and proposed rates. This customer with a peak demand of 10 MW and a 50% load factor taking service from a 100 kV or higher supply line would pay \$3,432, \$3,662 and \$3,862 for delivery service from AmerenCILCO, AmerenCIPS and AmerenIP under existing rates. This works out to a total cost per-kWh for delivery service of 0.094 cents/kWh, 0.100 cents/kWh and 0.105 cents/kWh for that customer under AmerenCILCO, AmerenCIPS and AmerenIP rates, respectively. If, as AIU witness Jones assumes, supply costs run approximately 4.5 cents/kWh, delivery costs account for approximately 2% of current total electricity costs for this customer. Even if rates for that customer were to double to approximately two-tenths of a cent per kWh for delivery, his/her electricity costs would increase by only 2%, an increase which Staff considers reasonable. (Staff Ex. 7.0, p. 21)

The Companies criticize this 150% constraint, claiming that it would produce disproportionate increases for the DS-3 class. According to AIU witness Jones, 835 AmerenIP DS-3 customers would receive total bill increases in the 10% range under Staff's proposal as compared to 455 customers under the Ameren proposal. (Ameren Ex. 40.0 (2nd Revised), p. 5)

This argument should be rejected. First, the Staff constraint is more consistent than the AIUs' proposal because it includes distribution taxes while theirs does not. Second, it should be remembered that the numbers of customers cited by Mr. Jones receive increases of this magnitude based on the revenue requirement the AIUs propose in this proceeding. To the extent that the Commission adjusts those revenue requirements downward due to proposals by Staff and intervenors, the figures cited by Mr. Jones will decline accordingly. (Staff Ex. 21.0, p. 13)

AIU witness Jones also seeks to defend the Companies' proposed revenue allocation to DS-5 lighting customers against Staff criticisms. For DS-5 customers of AmerenIP, Mr. Jones contends that "a decrease to AmerenIP's DS-5 class by an amount less than that indicated by the cost of service study was weighed against every other class receiving an increase of more than 20%." So, Ameren chose to increase revenues for the class above the cost of service. (Ameren Ex. 40.0 (Revised), p. 12) For AmerenCILCO, Mr. Jones considers the higher allocation acceptable because the proposed revenues are within 2% of the cost of service study results. (*Id.*) With respect to AmerenCIPS, Mr. Jones simply states that the "proposed DS-5 revenue is greater than its embedded cost." (*Id.*) Mr. Jones further seeks to justify the reasonableness of the Companies' approach by stating that "the AIUs rely on the fact that the incremental cost of lighting fixtures are well above the proposed prices for AmerenCIPS DS-5 service, and the proposed Fixture Charges for AmerenIP and AmerenCILCO remain higher than those for AmerenCIPS." (*Id.*)

Mr. Jones' discussion underscores the inconsistency and inequity in Ameren's allocation methodology. As he readily admits, the Companies have applied one standard to lighting customers and another to all remaining customers. This is clearly unfair to the lighting class. When utilities do factor bill impacts into the revenue allocation process, their approach should be based on a transparent set of rules fairly and consistently applied to all rate classes to ensure that some are not shortchanged in the process. The Companies' proposal clearly falls short in this regard. (Staff Ex. 21.0, p. 12)

The AIUs' double standard for the lighting class is exemplified by Mr. Jones' argument that higher DS-5 revenues are justified because the incremental cost of lighting fixtures exceeds revenues. While the AIUs bring incremental costs into the discussion of DS-5 revenue allocations, they are not factored into revenue allocations for any other rate classes. (*Id.*, p. 13)

b. Overall Rate Design

The Companies and Staff are in general agreement on rate design for the DS-1 and DS-2 classes. However, there is disagreement on how DS-3, DS-4 and DS-5 rates should be designed. For the reasons discussed in this brief, the Commission should adopt the rate design proposed by Staff for these three rate classes.

The DS-1 rates on which the Companies and Staff generally agree are based on the Companies' initial filing and include certain revisions suggested by Staff. One of those revisions concerns the withdrawal of the Companies' initial proposal to replace the separate customer and meter charges with a single fixed charge on customer bills.

As far as the levels for customer and meter charges are concerned, the Companies' proposals are consistent with Commission precedent and therefore acceptable for this proceeding. One of the AIUs' proposals is to make these combined charges uniform across the three Companies. A second proposal increases these charges significantly above current charges to recover a larger share of the utilities' fixed costs, in accordance with the Straight Fixed Variable (SFV) ratemaking approach favored by the Commission. (Staff Ex. 7.0, p. 24)

The AIUs support their proposals by citing to Commission statements in the Final Order for Docket Nos. 07-0585 et al. (Cons.). AIU witness Jones states that the Commission expressed a desire in that Order to return to uniform customer and meter charges as the Companies propose in this case. Mr. Jones further notes the Commission in that Order suggested that SFV pricing be considered for Residential Space Heating customers. (Ameren Ex. 16.0E (2nd Revised), pp. 20, 24) Mr. Jones expanded upon that discussion to propose higher SFV-based customer charges for all residential customers. Mr. Jones considers the movement to SVF pricing moderate since the AIUs' proposed customer and meter charges would only recover 39% of the base revenue requirement for residential customers. (*Id.*, p. 24)

Staff finds it difficult to oppose the Companies' proposals for residential customer charges given the Commission's stated preference for SFV rate design. Thus, Staff considers the proposals acceptable in this case. (Staff Ex. 7.0, p. 25)

The Companies and Staff also agree on the design of variable delivery and Basic Generation Service ("BGS") rates. The discussion of those rates is presented in the section entitled, "Tail Block Variable Charges: BGS-1."

DS-2 Rate Design

As previously noted, the Companies and Staff also are in agreement concerning the design of DS-2 rates. (Ameren Exhibit 55.0 (Revised), pp. 10-11) These rates should be adopted by the Commission.

The Companies' rate design proposals for Small General Service (DS-2) rates follow the same general principles employed for DS-1. First, they propose to significantly increase the size of the customer charge "to recover fixed costs beyond those traditionally considered customer-related." (Ameren Ex. 16.0E (2nd Revised), p. 30) Second, the Companies propose changes to BGS and variable delivery charges consistent with their recommendations for residential DS-1 customers. (*Id.*, pp. 30-31)

Staff reaches the same conclusion for the increases in DS-2 customer charges as for the AIUs' proposed DS-1 customer charges. Because the Commission strongly supports higher customer charges based on SFV principles, Staff does not oppose the Companies' proposal to raise these customer charges as well. (Staff Ex. 7.0, p. 30)

The Companies' proposed changes to variable BGS and delivery charges for DS-2 customers are also similar to their proposals for the Residential DS-1 class. For example, they propose to address a similar disconnect between DS-2 non-summer tail block BGS charges and attendant costs by raising BGS charges and reducing delivery service charges for this block. The AIUs propose to raise supply charges for non-summer usage in excess of 2,000 kWhs and reduce delivery service charges for this block to between 50% and 60% of current levels. According to AIU witness Jones, the combination of the two actions produces a maximum increase in variable charges for DS-2 bundled customers of 10.4%. (Ameren Ex. 16.0E (2nd Revised), pp. 30-31)

The Companies' proposals represent a reasonable solution to the challenges posed by the rate redesign conducted in Docket No. 07-0165. In that proceeding, the Commission faced a common problem of disproportionate bill impacts for customers with high consumption levels in non-summer months. For each class, the problem was addressed by reducing BGS supply charges for higher usage blocks in the non-summer months and increasing other BGS charges accordingly. (Staff Ex. 7.0, p. 31)

These adjustments in Docket No. 07-0165 have created a discrepancy between supply charges and costs. To reduce these imbalances, the Companies propose to move tail block non-summer rates closer to costs. (*Id.*, p. 32)

While Staff had suggested that the Commission consider raising non-summer tail block rates for the Residential DS-1 class, it does not make a similar proposal for DS-2 customers. That is because the gap between BGS charges and costs for bundled DS-2 customers in the non-summer tail block is not nearly as great as for residential DS-1 customers. For residential customers, the current per-kWh tail block supply charge for some residential customers falls to one cent or below while for bundled DS-2 customers the charge remains above 4 cents per kWh. This much smaller gap between supply charges and costs for residential space heating tail block usage provides the reason to suggest that the Commission consider going further than the Companies propose to raise that supply charge for residential customers. (*Id.*)

c. Recovery of Electric Distribution Tax/Public Utilities Revenue Act Tax

The Companies' initial filing included a proposal to recover distribution taxes in a separate Tax Additions Rider. (Ameren Ex. 16.0E (Revised), pp. 13-14) Staff, for its part, presented arguments in opposition to this proposal and argued for base rate recovery of these costs. (Staff Ex. 7.0, p. 12) The Companies then responded by withdrawing its rider proposal and accepting the base rate recovery alternative. (Ameren Exhibit 40.0 (2nd Revised), p. 2) Thus, there are no contested issues remaining concerning the Companies' rider proposal.

d. Distribution Delivery Charges: DS-3 and DS-4

The Companies' proposal to collectively design rates for the DS-3 and DS-4 classes conflicts with basic principles of utility ratemaking and should be rejected by the Commission. The Staff alternative of designing rates for the two classes based on their respective costs of service is more reasonable and should be adopted in this case.

The Companies' proposed rates include a common set of customer and meter charges for the two classes that are set at current levels. (Ameren Ex. 16.0E (2nd Revised), p. 34) For demand charges, the AIUs first develop a unit cost for demand that applies to both DS-3 and DS-4. That unit cost is then adjusted by the Companies "to reflect that revenue contributions from DS-3 will be slightly less than those for DS-4 through the year." Because of these adjustments, demand charges for the two classes diverge to some degree. (*Id.*, p. 40)

The AIUs justify this common approach to DS-3 and DS-4 rate design by referencing their last rate case (Docket Nos. 07-0585 et al. (Cons.)) in which the Commercial Group expressed a concern about the disparities between demand charges for the DS-3 and DS-4 classes. (Ameren Ex. 16.1E, p. 1) The AIUs further note that the Commission Order for that case discussed the possibility of combining rates DS-3 and DS-4 by stating that it "remains open to the possibility of restructuring rates DS-3 and DS-4 when sufficient information is available to fully analyze the implications of any restructuring, the Commission affirms its decision from Docket Nos. 06-0070/06-0071/06-0072 (Cons.) and directs AIU to address these two issues in its first electric rate cases filed in 2009 or thereafter." (Order, Docket Nos. 07-0585 et al. (Cons.), September 24, 2008, pp. 362-63)

The Companies have prepared an analysis to support their ratemaking approach for the two classes. A central tenet of the analysis is the assumption that "[c]onceptually, it costs about the same to provide a kW of service to a DS-3 customers as it does a DS-4 customer." The analysis thereby finds that "the $/kW charges for DS-3 and DS-4 should be close together." (Ameren Ex. 16.1E, p. 1)

The problem with the analysis lies with the assumption that "it costs about the same" to provide a kW of service" to DS-3 and DS-4 customers. That is not necessarily the case because a customer's impact on the distribution system depends not just on the level of his or her demand, but also on when that demand takes place. That is particularly true for facilities such as distribution lines and substations may be constructed to meet the collective peak demands of many customers from different rate classes. The impact of any individual customer's demand on the cost of a distribution line or substation depends on how his or her demand coincides with the peak demand for that equipment. If one customer peaks when other customers use less, then that customer may have minimal impact on the cost of a distribution line or substation. If another customer's peak demands coincide with the collective peak demands for this equipment, then the utility may find it necessary to invest in more capacity. (Staff Ex. 7.0, p. 35)

These two examples show that not all electricity demands are the same from the standpoint of distribution costs. Thus, there is no reason to assume that unit demand costs for DS-3 and DS-4 customers will be comparable. (*Id.*, p. 36)

Another problem is that the Companies' combined ratemaking approach for DS-3 and DS-4 conflicts with general ratemaking principles which first allocate costs to individual rate classes and then design rates to recover those costs from individual ratepayers. Customers are placed into different rate classes because their usage characteristics are assumed to have a differing effect on system costs. The AIUs' combined approach does not fully recognize these cost differences and instead essentially treats DS-3 and DS-4 as a single class for ratemaking purposes with some adjustments thrown in to reflect some differences between the two classes. Thus, the Companies' proposal would send inaccurate price signals to DS-3 and DS-4 customers about their relative cost of delivery services. Specifically, it would understate the cost of delivery service for DS-3 customers and overstate the cost for DS-4 customers. This would signal customers in the two classes to use either too much or too little electricity, resulting in an inefficient level of use. (*Id.*, p. 36)

This assumption of commonality between DS-3 and DS-4 customers for rate design inappropriately lumps together customers that are much different in size. Customers in the DS-3 class have demands ranging from 150 kV up to 1 MW while DS-4 class demands range higher. A common rate design for the two classes would lump together 150 kW customers with customers 10 MW or larger. The cost of serving these two customers can be considerably different simply because of their relative demand sizes without considering their respective load shapes. (*Id.*, p. 37)

AIU witness Jones seeks to defend the Companies' rate design methodology for DS-3 and DS-4 against Staff's criticisms. Mr. Jones also takes issue with Staff's alternative approach for these two classes, contending it would produce unwelcome incentives for larger DS-3 customers. (Staff Ex. 21.0, p. 15)

Mr. Jones contends that Staff incorrectly surmises that the AIUs' "common rate design for the two classes would lump together 150 kW customers served at lower voltage levels with customers 10 MW or higher taking service from transmission lines above 100 kV." (Ameren Ex. 40.0 (2nd Revised), p. 8) Mr. Jones seeks to assure that is not the case because "the AIUs' rate design method carefully groups customers by voltage level such that customers' demands supplied from Primary Voltage are grouped together, as are those from High Voltage and +100 kV groupings." (*Id.*, pp. 8-9)

Mr. Jones' argument is undermined by the fact that DS-3 and DS-4 customers face the same set of customer charges with differences based solely on voltage levels under the AIUs' proposal. So, for instance, a 500 kW DS-3 customer could pay a higher customer charge than a 5 MW DS-4 customer if the former was served at a higher voltage level. The fact that the DS-4 customer's demand is ten times as high as for the DS-3 customer would play no role in determining their relative customer charge levels. This is an unreasonable assumption on the Companies' part. (Staff Ex. 21.0, p. 16)

In addition, as discussed previously, Ameren develops distribution charges for the DS-3 and DS-4 classes in a collective manner. Thus, 150 kW customers are lumped together with 10 MW customers for determining these charges as well. (*Id.*)

It should further be noted that Ameren's cost of service and rate design approaches for these two classes are fundamentally inconsistent. That is because Ameren considers DS-3 and DS-4 different classes from a cost of service standpoint, but then lumps them together for the purpose of designing rates. Evidently, Ameren believed there were sufficient cost differences between the two groups of customers to justify putting them into two separate classes for allocating the cost of service. However, Ameren then failed to recognize those differences in cost when it comes to rate design. Mr. Jones fails to provide a reasonable explanation for these two conflicting approaches. (*Id.*, p. 18)

The contradiction in the Companies' approach is exemplified by Mr. Jones' discussion of DS-3 and DS-4 rates in surrebuttal where he states, "[t]o be clear, the AIUs have not proposed to combine the DS-3 and DS-4 rate classes at this time. Each class remains somewhat unique, with its own revenue allocation targets." (Ameren Ex. 55.0 (Revised), p. 11) This statement reveals the confusing muddle of the AIUs' proposed rates for the two classes. By claiming the two sets of rates are "somewhat unique," Mr. Jones is admitting there are no clear, straightforward principles guiding the proposed rates for these two classes. Rather the proposal is caught somewhere in the middle and it is not clear what cost standards they are designed to reflect.

Mr. Jones does acknowledge Staff's argument concerning cost differences between the DS-3 and DS-4 classes, stating Staff is "correct that one class may have a greater contribution to the peak demand than another, thus yielding different costs per kW." (Ameren Ex. 40.0 (2nd Revised), p. 8) Nevertheless, that does not prevent him from continuing to advocate the collective design of delivery charges for the two classes.

Staff has presented a more reasonable alternative which designs rates separately for the two classes based on the respective costs and billing determinants for each class. This is a consistent approach which treats DS-3 and DS-4 as separate classes for both cost allocation and rate design. Designing rates for DS-3 and DS-4 separately promotes equity by ensuring that customers in each class pay rates designed to recover the costs that have been allocated to that class. The alternative approach of collectively designing charges that apply to both the DS-3 and DS-4 classes produces rates for customers in each class that do not necessarily correspond to the level of costs they have been allocated. That can result in an over-recovery of costs for one class and under-recovery for the other. Clearly the Staff alternative is the more reasonable rate design methodology for DS-3 and DS-4 and it should be adopted in this proceeding. (Staff Ex. 7.0, pp. 37-38)

Mr. Jones criticizes Staff's proposal for the two classes, arguing the lower DS-4 rates that result would encourage some of the largest DS-3 users to increase demand to qualify for DS-4 rates. While it is possible that some of the largest DS-3 customers may attempt to do this, Mr. Jones has provided no evidence about the number of customers that would benefit by migrating and whether the number and revenue impacts would be meaningful. It certainly does not provide sufficient reason to retreat from cost-based rates for the two classes. (Staff Ex. 21.0, p. 16)

e. Fixture and Distribution Delivery Charges: DS-5

Staff's proposed rate design for the DS-5 lighting class should be adopted. That approach would revise the AIUs' proposed lighting rates for each Company on an equal percentage basis to conform to Staff's recommended revenue allocations for the lighting classes. This approach will best ensure that lighting customers only pay their fair share of system costs. (Staff Ex. 7.0, p. 40)

AIU witness Jones argues that Staff's proposed lighting rates are flawed because they are derived from the Company's current rates for the class and therefore the approach "ignores the arguments of the Cities from Docket No. 07-0585 et al. (Cons.) that Fixture Charges be brought closer together, and does not adequately address the Commission's inquiries about moving Fixture Charges closer together expressed in the prior rate order." (Ameren Ex. 40.0 (2^{nd} Revised), p. 11)

Mr. Jones' criticism is erroneous. The starting point for Staff's proposed rates is Ameren's proposed rate design which incorporates movement toward more equal charges. However, that movement must be balanced with an allocation of the revenue requirement that is equitable to all rate classes. Staff's proposed revenue allocations for the AIU are fair to all rate classes and Staff's rate design for the lighting class which flows directly from the Companies' proposed rates and adjusted to conform to Staff' proposed class revenues are reasonable as well. (Staff Ex. 21.0, pp. 19-20)

f. Tail Block Variable Charges: BGS-1

The Companies and Staff are in agreement concerning the development of all variable charges including tail block BGS charges. These charges should be approved in the Commission's Order.

With respect to charges for BGS service, the AIUs propose to reduce the current disparities between BGS charges and costs. These disparities which depend on the usage block in which consumption takes place and on whether the customer uses electricity for space heating have within the residential class have resulted in the following set of existing BGS charges for residential usage over 800 kWhs during the non-summer months:

(In Cents/kwh)

CIPS-SH	CIPS-NSH	CIPS-ME	CILCO	IP-SH	IP-NSH
2.367	5.104	0.992	2.334	0.885	4.856

(Ameren Ex. 16.0E (2nd Revised), p. 22)

As AIU witness Jones notes, the Companies pay a weighted average price of power through the IPA of just under 5 cents/kWh for non-summer months. (*Id.*) Thus, the AIUs incur a shortfall of approximately 4 cents for each kWh sold to CIPS-Metro East and IP-Space Heating customers, as well as a deficit of between 2 and 3 cents for each kWh sold to CIPS-SH customers during this period. (Staff Ex. 7.0, p. 26)

The Companies have good reason to reduce these disparities. By charging space heating customers less than the cost of supplying power, the price signal encourages them to use more electricity. This increased usage burdens all remaining bundled customers who must make up the shortfall by paying a price for electricity that exceeds the cost. (*Id.*, p. 26)

The gap between rates and costs also makes the collection of supply cost revenues uncertain. To bring supply revenues and costs into balance, the lower non-summer tail block charges for space heating customers must be balanced by an above-cost charge for residential customers in other periods. The levels of these charges are based on assumptions about how residential customers use electricity throughout the year. If those assumptions prove wrong, then supply revenues diverge from supply costs and adjustments must be made to the supply charges that bundled customers pay. (*Id.*)

The Companies seek to address this problem through a combined proposal that reduces the gap between winter tail block BGS rates and associated costs through BGS charge and delivery service rate adjustments. Their proposal centers on increasing the BGS charge and lowering the delivery service charge for the non-summer over 800 kWh consumption block. Furthermore, the Companies would limit the increase in the combined tail block BGS and distribution charges for the non-summer period to 10% over the current levels. (*Id.*, pp. 26-27)

This proposal will reduce the potential for supply charges to fall out of alignment with costs and thereby bring the two into closer balance. In addition, the proposal to raise the non-summer tail block distribution rate appears to have some cost justification. AIU witness Althoff prepared a set of cost of service study results for residential space heating customers. Those results indicate that revenues are significantly higher relative to costs for space heating customers than non-space heating customers under current rates. (Ameren Ex. 16.0E (2nd Revised), p. 23) This greater excess of revenues over costs for space heating customers would justify a lower distribution rate in the winter tail block where their usage disproportionately takes place. (Staff Ex. 7.0, pp. 27-28)

With respect to the Companies' proposed 10% limitation on changes in tail block charges for space heating customers, Staff recommends that the Commission consider raising these combined tail block supply and delivery charges for space heating customers even further in this proceeding. Supply costs for bundled customers fell significantly in June of this year, approximately 13% on average for the residential customers of the Companies. Since supply costs account for considerably more than half of residential ratepayer bills, all residential customers have received lower bills as a result. Furthermore, residential space heating customers will receive lower bills this winter because of the June reductions in supply charges. (*Id.*, p. 28)

Clearly, it is too soon to eliminate all subsidies of heating customers by non-heating customers in this case. The strong reaction to the January 2007 expiration of the rate freeze demonstrates the need for further caution. Nevertheless, the 13% reduction in supply charges this June could serve as a buffer for further increases in supply charges for space heating customers beyond the levels proposed by the AIUs. (*Id.*, p. 29)

There is another reason to consider a further increase in these tail block charges beyond the levels proposed by the AIUs. The Commission signaled its intention in the Companies' previous case to return Ameren ratemaking to cost-based ratemaking. The below-cost non-summer tail block supply charges for space heating customers clearly conflict with these principles. Thus, the Commission can signal its intention to return to cost-based ratemaking by reducing the level of subsidy in these tail block rates by raising the supply charges further than the AIUs propose. (*Id.*)

AIU witness Jones notes Staff's agreement "with the approach and designs for DS-1 and DS-2, and the resultant changes to BGS-1 and BGS-2 prices." (Ameren Ex. 40.0 (2nd Revised), p. 13) Mr. Jones also discusses the Staff recommendation for a slightly larger increase in non-summer tail block rates beyond Ameren's proposal to more aggressively reduce subsidies to electric space heating customers. Mr. Jones does not oppose the proposal and, instead, explores the potential impacts it would have on these ratepayers, finding that "a customer using 18,000 kWh per year would experience an annual increase of about $1.50 at AmerenIP, $3.50 at AmerenCIPS, $1.00 at AmerenCIPS-ME, and $4.50 at AmerenCILCO." (*Id.*, p. 14)

Mr. Jones' discussion also shows that these additional annual increases would be very modest. Furthermore, it should be remembered that these impacts are based upon the revenue requirements proposed by Ameren in this case. To the extent that the Commission adjusts electric revenue requirements downwards, adverse bill impacts for space heating customers will be reduced. Thus, it would be reasonable to adopt this proposal for non-summer tail block rates at this time. (Staff Ex. 21.0, pp. 14-15)

If the Commission were to approve lower revenue requirements than proposed by the AIUs, it could decide to maintain the combined increase in BGS and delivery non-summer tail block charges at 10%. Other delivery and fixed charges could be reduced on an equal percentage basis while the increase in the tail block delivery charge remains fixed to produce this 10% combined increase. (Staff Ex. 7.0, p. 29)

g. Combined Billing of Multiple Meters

h. Rate Limiter/Cost-Based Seasonal Rate

The Company and Staff agree on the proposed approach to the rate limiter. (Ameren Ex. 55.0 (Revised), p. 17) This proposal should be adopted in the Commission Order for this case.

The rate limiter is a measure designed to limit increases in delivery service charges to address adverse impacts for DS-3 and DS-4 customers that use most of their electricity during non-summer months. The rate limiter ensures for these customers that total delivery services costs on a per-kWh basis do not rise above a set, fixed amount. It was instituted in conjunction with the 2007 rate redesign case which sought to temper the largest increases incurred by Ameren customers when the rate freeze expired in January 2007. The limiters which are the same both for DS-3 and DS-4 customers are currently set at 2.613, 2.223 and 1.953 cents per-kWh for AmerenIP, AmerenCIPS and AmerenCILCO customers, respectively. (Ameren Ex. 16.0E (2nd Revised), p. 42)

The AIUs propose in this case to increase the rate limiters to a level that preserves the current level of subsidy for the eligible customers. This produces rate limiter levels of 4.000, 3.000 and 3.000 cents per-kWh for AmerenIP, AmerenCIPS and AmerenCILCO customers, respectively. (*Id.*) The AIUs note the Commission statement in their previous rate cases (Docket Nos. 07-0585 et al. (Cons.)) that it "is committed to eliminating these rate limiters at the earliest opportunity; however, the Commission concludes that the time to do so has not yet arrived." (Ameren Ex. 16.0E (2nd Revised), p. 42) The Companies believe their proposal provides the appropriate balance between addressing bill impacts issues for these customers and phasing this temporary measure out. (*Id.*)

This is a reasonable proposal. As the Companies' proposals attest, the movement toward cost-based rates in this proceeding must continue to take into account bill impacts for retail customers. The Companies' proposals in this case include constraints on revenue increases for individual rate classes as well as continued efforts to limit adverse impacts for large non-summer users in the DS-1 and DS-2 classes. Thus, it would be consistent with these efforts to maintain the rate limiter. At the same time, the Commission has clearly signaled that the rate limiter is a temporary program that should be eliminated when the opportunity arises. The Companies propose significant increases in the levels of the rate limiters in order to maintain attendant subsidies for eligible customers at current levels. These increases will make it possible for the Commission in the near future to remove this constraint and place these customers under the same rate tariffs that apply to other DS-3 and DS-4 customers. (Staff Ex. 7.0, pp. 39-40)

i. Other

Adjusting Rates to Final Revenue Requirement

If the Commission approves a revenue requirement lower than the Companies proposed, it should apply an equal percentage downward adjustment to all of Staff's proposed charges for retail customers. That is the most simple and straightforward approach for the Commission to take and the resulting rates that are produced would be most consistent with the methodology proposed. (Staff Ex. 7.0, p. 41)

AIU witness Jones advocates an alternative approach which would adjust only variable delivery charges and not make any changes to proposed Customer and Meter charges. (Ameren Ex. 55.0 (Revised), p. 9) As Mr. Jones concedes, "an across the board approach is an easy way to set final rates" whereas "the AIUs approach has a few more directions to follow" (*Id.*, p. 8) Nevertheless, he considers the Companies' approach superior because it would allow the Commission to make further progress to rate design objectives. (*Id.*)

Compliance rates are not a good place in which to adjust rates for specific rate design objectives. Any changes to rates at that juncture have important implications for all Ameren ratepayers. To the extent that one rate element is adjusted and another is not, certain ratepayers will benefit while others will be disadvantaged. The problem is that no ratepayers have recourse at this stage of the process. If a group of customers loses out, they must wait until the next rate case to seek redress. In contrast, the Staff equal percentage adjustment approach to compliance rates has the same impact on all ratepayers. Thus, ratepayers will know they receive the same treatment as everyone else in the adjustment of their rates to the final revenue requirement. This is clearly more transparent and more equitable as well.

VIII. CONCLUSION

WHEREFORE, for all of the following reasons, Staff respectfully requests that the Commission's order in this proceeding reflect all of Staff's recommendations regarding the Company's request for a general increase in electric and gas rates.

January 14, 2010

Respectfully submitted,

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AmerenCILCO - Electric
Statement of Operating Income with Adjustments
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Company Rebuttal Present (Ex. 29.1, Sch. 1)	Staff Adjustments (Appendix A Page 4)	Staff Pro Forma Present (Cols. b+c)	Company Rebuttal Proposed Increase (Ex. 29.1, Sch. 1)	Staff Gross Revenue Conversion Factor	Proposed Rates With Staff Adjustments (Cols. d+e+f)	Adjustment To Proposed Increase	Staff Pro Forma Proposed (Cols. g+h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Electric Operating Revenues	$ 116,954	$ -	$ 116,954	$ 21,620	$ -	$ 138,574	$ (16,620)	$ 121,954
2	Other Revenues	5,043	-	5,043	-	-	5,043	-	5,043
3	Total Operating Revenue	121,997	-	121,997	21,620	-	143,617	(16,620)	126,997
4	Uncollectible Accounts	986	-	986	175	-	1,161	(134)	1,027
5	Distribution Expenses	31,030	(897)	30,133	-	-	30,133	-	30,133
6	Customer Accounts Expense	9,063	(124)	8,939	-	-	8,939	-	8,939
7	Admin & General Expense	29,700	(5,547)	24,153	-	-	24,153	-	24,153
8	Depreciation & Amort Expense	21,242	(145)	21,097	-	-	21,097	-	21,097
9	Taxes Other Than Income	7,459	(869)	6,590	-	-	6,590	-	6,590
10			-	-	-	-	-	-	-
11			-	-	-	-	-	-	-
12			-	-	-	-	-	-	-
13			-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	99,480	(7,583)	91,897	175	-	92,072	(134)	91,938
							-		-
17	State Income Tax	572	812	1,384	1,565	1	2,950	(1,203)	1,747
18	Federal Income Tax	2,547	3,616	6,163	6,958	-	13,121	(5,349)	7,772
19		-	-	-	-	-	-	-	-
20	Total Operating Expenses	102,599	(3,155)	99,444	8,698	1	108,143	(6,686)	101,457
21	NET OPERATING INCOME	$ 19,398	$ 3,155	$ 22,553	$ 12,922	$ (1)	$ 35,474	$ (9,934)	$ 25,540
22	Staff Rate Base (Appendix A, Page 5, Column (d))								$ 308,454
23	Staff Overall Rate of Return (ICC Staff Exhibit 19.0R, Schedule 19.01 CILCO)								8.28%
24	Revenue Change (Col. (i) Line 3 minus Col. (d), Line 3)								$ 5,000
25	Percentage Revenue Change (Col. (i), Line 24 divided by Col. (d), Line 3)								4.10%

AmerenCILCO - Electric
Adjustments to Operating Income
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Interest Synchronization (Appendix A Page 7)	Incentive Compensation (St. Ex. 15.0 Sch 15.07-CILCO-E)	Employee Benefits Exp. (St. Ex. 15.0 Sch 15.09-CILCO-E)	Workforce Reduction (Appendix A Page 13)	Production Retiree Expense (St. Ex. 15.0 Sch 15.11 CILCO-E)	Electric Distribution Tax (St. Ex. 15.0 Sch 15.12 CILCO-E)	(Source)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-			-
5	Distribution Expenses	-	-	-	-	-			-
6	Customer Accounts Expense	-	-	-	-	-			-
7	Admin & General Expense	-	(710)	(4,082)	(922)	368			(5,346)
8	Depreciation & Amort Expense	-	(6)	-		-	-	-	(6)
9	Taxes Other Than Income	-	(68)	-	(55)	-	(746)		(869)
10		-	-	-	-	-	-	-	-
11		-	-	-	-	-	-	-	-
12		-	-	-	-	-	-	-	-
13		-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	-	(785)	(4,082)	(977)	368	(746)	-	(6,222)
								-	
17	State Income Tax	260	57	298	71	(27)	54	-	713
18	Federal Income Tax	1,155	255	1,324	317	(119)	242	-	3,174
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	1,415	(473)	(2,460)	(589)	222	(450)	-	(2,335)
21	NET OPERATING INCOME	$ (1,415)	$ 473	$ 2,460	$ 589	$ (222)	$ 450	$ -	$ 2,335

AmerenCILCO - Electric
Adjustments to Operating Income
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Pro Forma Plant Additions (St. Ex. 16.0 Sch 16.01 CILCO-E Corrected)	NESC Adjustment (St. Ex. 16.0 Sch 16.03 CILCO-E)	Transportation Fuel Costs (St. Ex. 17.0 Sch 17.01 CILCO-E)	Tree Trimming (St. Ex. 17.0 Sch 17.02 CILCO-E)	Lobbying Expense (St. Ex. 18.0R Sch 18.01 CILCO-E)	Industry Association Dues (St. Ex. 18.0R Sch 18.03 CILCO-E)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Distribution Expenses	-	-	(154)	(180)	(563)	-	-	(897)
6	Customer Accounts Expense	-	-	-	-	-	-	-	-
7	Admin & General Expense	(5,346)	-	-	-		(3)	(92)	(5,441)
8	Depreciation & Amort Expense	(6)	(145)	6	-	-	-		(145)
9	Taxes Other Than Income	(869)	-	-	-	-	-	-	(869)
10		-	-	-	-	-	-	-	-
11		-	-	-	-	-	-	-	-
12		-	-	-	-	-	-	-	-
13		-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	(6,222)	(145)	(148)	(180)	(563)	(3)	(92)	(7,353)
17	State Income Tax	713	11	11	13	41	-	7	796
18	Federal Income Tax	3,174	47	48	58	183	1	30	3,541
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	(2,335)	(87)	(89)	(109)	(339)	(2)	(55)	(3,016)
21	NET OPERATING INCOME	$ 2,335	$ 87	$ 89	$ 109	$ 339	$ 2	$ 55	$ 3,016

AmerenCILCO - Electric
Adjustments to Operating Income
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Customer Service & Info. Expense (St. Ex. 18.0R Sch 18.04 CILCO-E)	Homer Works HQ Sale (St. Ex. 18.0R Sch 18.05 CILCO-E)	Demonstrating & Selling Expense (St. Ex. 18.0R Sch 18.06 CILCO-E)	(Source)	(Source)	(Source)	Total Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Distribution Expenses	(897)		-	-	-	-	-	(897)
6	Customer Accounts Expense	-	(124)	-	-	-	-	-	(124)
7	Admin & General Expense	(5,441)	-	(18)	(88)				(5,547)
8	Depreciation & Amort Expense	(145)	-	-	-	-	-	-	(145)
9	Taxes Other Than Income	(869)	-	-	-	-	-	-	(869)
10		-	-	-	-	-	-	-	-
11		-	-	-	-	-	-	-	-
12		-	-	-	-	-	-	-	-
13		-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	(7,353)	(124)	(18)	(88)	-	-	-	(7,583)
17	State Income Tax	796	9	1	6	-	-	-	812
18	Federal Income Tax	3,541	40	6	29	-	-	-	3,616
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	(3,016)	(75)	(11)	(53)	-	-	-	(3,155)
21	NET OPERATING INCOME	$ 3,016	$ 75	$ 11	$ 53	$ -	$ -	$ -	$ 3,155

AmerenCILCO - Electric
Rate Base
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Company Rebuttal Rate Base (Ex. 29.1, Sch. 2)	Staff Adjustments (Appendix A Page 6)	Staff Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Plant in Service	$ 864,685	$ (5,474)	$ 859,211
2	Accumulated Depreciation	(466,000)	(910)	(466,910)
3	-	-	-	-
4	Net Plant	398,685	(6,384)	392,301
5	Additions to Rate Base			
6	Cash Working Capital	1,137	(623)	514
7	Materials & Supplies Inventory	5,298	(558)	4,740
8	CWIP Not Subject to AFUDC	189	-	189
9	-	-	-	-
10	-	-	-	-
11	-	-	-	-
12	-	-	-	-
13	-	-	-	-
14	-	-	-	-
15	-	-	-	-
16	Deductions From Rate Base			
17	Customer Advances	(5,853)	-	(5,853)
18	Accumulated Deferred Income Taxes	(60,362)	169	(60,193)
19	Customer Deposits	(3,167)	-	(3,167)
20	Accrued OPEB Liability	-	(20,077)	(20,077)
21	-	-	-	-
22	-	-	-	-
23	Rate Base	$ 335,927	$ (27,473)	$ 308,454

AmerenCILCO - Electric
Adjustments to Rate Base
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Incentive Compensation (St. Ex. 15.0 Sch 15.07-CILCO-E)	Cash Working Capital (Appendix A Page 9)	Pro Forma Plant Additions (St. Ex. 16.0 Sch 16.01 CILCO-E Corrected)	NESC Adjustment (St. Ex. 16.0 Sch 16.03 CILCO-E)	Materials & Supplies (Appendix A Page 15)	Accrued OPEB Liabilities (AG/CUB Exhibit 2.1)	(Source)	Total Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Plant in Service	$ (183)	$ -	$ (5,076)	$ (215)	$ -	$ -	$ -	$ (5,474)
2	Accumulated Depreciation	(6)	-	(909)	5	-	-	-	(910)
3	-	-	-	-	-	-	-	-	-
4	Net Plant	(189)	-	(5,985)	(210)	-	-	-	(6,384)
	-								
5	Additions to Rate Base								-
6	Cash Working Capital	-	(623)	-	-	-	-	-	(623)
7	Materials & Supplies Inventory	-		-	-	(558)	-	-	(558)
8	CWIP Not Subject to AFUDC	-	-	-	-		-	-	-
9	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-
16	Deductions From Rate Base	-	-	-	-	-	-	-	-
17	Customer Advances	-	-	-	-	-	-	-	-
18	Accumulated Deferred Income Taxes	4	-	120	45	-	-	-	169
19	Customer Deposits	-	-	-	-	-	-	-	-
20	Accrued OPEB Liability	-	-	-	-	-	(20,077)	-	(20,077)
21		-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-
	-								
23	Rate Base	$ (185)	$ (623)	$ (5,865)	$ (165)	$ (558)	$ (20,077)	$ -	$ (27,473)

AmerenCILCO - Electric
Interest Synchronization Adjustment
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Amount	
	(a)	(b)	
1	Gross Plant in Service	$ 308,454	(1)
2	Weighted Cost of Debt	3.600%	(2)
3	Synchronized Interest Per Staff	11,104	
4	Company Interest Expense	14,663	(3)
5	Increase (Decrease) in Interest Expense	(3,559)	
6	Increase (Decrease) in State Income Tax Expense		
7	at 7.300%	$ 260	
8	Increase (Decrease) in Federal Income Tax Expense		
9	at 35.000%	$ 1,155	

(1) Source: Appendix A, Page 5, Column (d), Line 23.
(2) Source: ICC Staff Exhibit 19.0R, Schedule 19.01 CILCO.
(3) Source: Ameren Exhibit 29.1, Schedule 3

AmerenCILCO - Electric
Gross Revenue Conversion Factor
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(a)	(b)	(c)	(d)
1	Revenues		1.000000	
2	Uncollectibles	0.8086%	0.008086	
3	State Taxable Income		0.991914	1.000000
4	State Income Tax	7.3000%	0.072410	0.073000
5	Federal Taxable Income		0.919504	0.927000
6	Federal Income Tax	35.0000%	0.321826	0.324450
7	Operating Income		0.597678	0.602550
8	Gross Revenue Conversion Factor Per Staff		1.673142	1.659613

Ameren/CILCO Electric
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Description (a)	Amount (b)	Source (c)
1	Cash Working Capital per Staff	$ 514	Appendix A, Page 10, Column e, Line 22
2	Cash Working Capital per Company	1,137	Ameren Ex. 29.1, Schedule 2, page 4, column (G), line 24
3	Difference -- Staff Adjustment	$ (623)	Line 1 less Line 2

Ameren/CILCO Electric
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Item (a)	Amount (b)	Lag (Lead) (c)	CWC Factor (d) (c/365)	CWC Requirement (e) (b*d)	Column C Source (f)
1	Revenues	$ 90,438	46.550	0.12753	$ 11,534	Appendix A, Page 11, Column b, Line 7
2	Pass-through Taxes	2,402	0.000	0.00000	-	Line 12 + Line 13 below
3	Total Receipts	$ 92,840				Line 1 + Line 2
4	Employee Benefits	$ 2,819	(17.570)	(0.04814)	(136)	Appendix A, Page 12, Column b, Line 16
5	Payroll	21,574	(12.920)	(0.03540)	(764)	Appendix A, Page 12, Column b, Line 5
6	Purchased Power	-	(18.146)	(0.04971)	-	
7	Other Operations and Maintenance	38,832	(51.070)	(0.13992)	(5,433)	Appendix A, Page 11, Column b, Line 17
8	FICA	854	(14.740)	(0.04038)	(34)	Appendix A, Page 12, Column b, Line 11
9	Federal Unemployment Tax	7	(76.380)	(0.20926)	(1)	Company Schedule C-18, Column J, Line 3
10	State Unemployment Tax	(31)	(76.380)	(0.20926)	6	Company Schedule C-18, Column J, Line 7
11	Electricity Distribution Tax	5,042	(30.130)	(0.08255)	(416)	ICC Staff Ex. 15.0, Sch. 15.12 CILCO-E, Column b, Line 1
12	Federal Excise Tax	-	(45.630)	(0.12501)	-	Company Schedule C-18, Column J, Line 4
13	Energy Assistance Tax	2,402	(42.280)	(0.11584)	(278)	Company Schedule C-18, Column H, Line 9
14	Corporation Franchise Tax	233	(191.530)	(0.52474)	(122)	Company Schedule C-18, Column J, Line 8
15	Gross Receipts/Municipal Utility Ta	-	(45.630)	(0.12501)	-	Company Schedule C-18, Column J: Line 11 + Line 15
16	Property/Real Estate Tax	485	(392.700)	(1.07589)	(522)	Company Schedule C-18, Column J, Line 14
17	Interest Expense	10,240	(91.250)	(0.25000)	(2,560)	Appendix A, Page 7, Line 3 - Line 18
18	Bank Facility Fees	864	97.650	0.26753	231	Appendix A, Page 5, Column d, line 23 times Bank Facility Fees Weighted Component Sched. 19.01
19	Federal Income Tax	7,772	(38.000)	(0.10411)	(809)	Appendix A, Page 1, Column i, Line 18
20	State Income Tax	1,747	(38.000)	(0.10411)	(182)	Appendix A, page 1, Column i, Line 17
21	Total Outlays	$ 92,840				Sum of Lines 4 through 20
22	Cash Working Capital per Staff				$ 514	Sum of Lines 1 through 20

Ameren/CILCO Electric
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Revenues (a)	Amount (b)	Source (c)
1	Total Operating Revenues	$ 126,997	Appendix A, Page 1, Column i, Line 3
2	Purchased Power	-	
3	Uncollectible Accounts	(1,027)	Appendix A, Page 1, Column i, Line 4
4	Depreciation & Amortization	(21,097)	Appendix A, Page 1, Column i, Line 8
5	Return on Equity	(14,436)	Line 10 below
6		-	
7	Total Revenues for CWC calculation	$ 90,438	Sum of Lines 1 through 6
8	Total Rate Base	$ 308,454	Appendix A, Page 5, Column d, Line 23
9	Weighted Cost of Capital	4.68%	ICC Staff Ex. 19.0R, Schedule 19.01 CILCO
10	Return on Equity	$ 14,436	Line 8 times Line 9
11	Operating Expense Before Income Taxes	$ 91,938	Appendix A, Page 1, Column i, Line 16
12	Employee Benefits Expense	(2,819)	Appendix A, Page 12, Column b, Line 16
13	Payroll Expense	(21,574)	Appendix A, Page 12, Column b, Line 5
14	Uncollectible Accounts	(1,027)	Appendix A, Page 1, Column i, Line 4
15	Depreciation & Amortization	(21,097)	Appendix A, Page 1, Column i, Line 8
16	Taxes Other Than Income	(6,590)	Appendix A, page 1, Column i, Line 9
17	Other Operations & Maintenance for CWC Calculation	$ 38,832	Sum of Lines 11 through 16

Ameren/CILCO Electric
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Description (a)	Amount (b)	Source (c)
1	Direct Payroll per Company Filing	$ 23,693	Company Schedule B-8, Column F, Line 2
2	Staff Labor Adjustment	(687)	ICC Staff Ex. 1.0, Sch. 1.09 CILCO-E, Line 3
3	Adjustment for Workforce Reduction	(722)	Appendix A, Page 13, line 1
4	Adjustment for Incentive Compensation	(710)	ICC Staff Ex. 15.0, Sch. 15.07 CILCO-E, Page 1, Line 6
5	Direct Payroll per Staff	$ 21,574	Sum of Lines 1 through 4
6	FICA tax per Company Filing	$ 1,051	Company Schedule C-18, Column J, Line 2
7	Labor Adjustment	(53)	ICC Staff Ex. 1.0, Sch. 1.09 CILCO-E, Line 5
8	Incentive Compensation Adjustment	(68)	ICC Staff Ex. 15.0, Sch. 15.07 CILCO-E, Page 1, Line 20
9	Adjustment for Workforce Reduction	(55)	Appendix A, Page 13, line 3
10	Company FICA Correction Adjustment	(21)	ICC Staff Ex. 1.0, Sch. 1.11 CILCO-E, Line 13
11	FICA tax per Staff	$ 854	Sum of Lines 6 through 10
12	Employee Benefits per Company Filing	$ 6,733	Company Schedule B-8, Column F, Line 1
13	Staff Adjustment for Benefits	(4,082)	ICC Staff Ex. 15.0, Sch. 15.09 CILCO-E, Line 6
14	Adjustment for Workforce Reduction	(200)	Appendix A, Page 13, line 2
15	Staff Adjustment for Retiree Benefits	368	ICC Staff Ex. 15.0, Sch. 15.11 CILCO-E, Line 5
16	Employee Benefits per Staff	$ 2,819	Sum of Lines 12 through 15

AmerenCILCO - Electric
Adjustment for Workforce Reduction
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description (a)	Amount (b)	Source (d)
1	Staff Proposed Compensation Savings	$ (722)	Appendix A, Page 14 line 14
2	Company CompensationSavings Rebuttal	-	
3	**Staff Proposed Adjustment**	$ (722)	
4	Staff Pension & Benefits Proposed Savings	$ (200)	Appendix A, Page 14 line 20
5	Company Pension & Benefits Savings Rebuttal	-	
6	**Staff Proposed Adjustment**	$ (200)	
7	**Taxes Other Than Income Adjustment**	$ (55)	Appendix A, Page 14, line 22

AmerenCILCO - Electric
Adjustment for Workforce Reduction
For the Test Year Ending 12/31/2008
(in Dollars)

Line No.	Description	AIU Amount	AMS Amount	Source
	(a)	(b)	(c)	(d)
1	Salaries (Involuntary)	$ 165,396	$ 112,535	Company Exhibit 51.9 workpaper
2	Salaries (Voluntary)	325,464	111,547	Company responses to Staff data requests TEE 18.02
3	Total Salaries	$ 490,861	$ 224,082	
4	Incentive Compensation (Involuntary)	$ 12,747	$ 11,652	Company Exhibit 51.9 workpaper
5	Incentive Compensation (Voluntary)	70,965	16,870	Company responses to Staff data requests TEE 18.02
6	Total Incentive Compensation	$ 83,712	$ 28,522	
7	Percent of Total IC in Revenue Requirement	16%	16%	Line 25
8	Total Incentive Compensation	$ 13,352	$ 4,549	Line 6 * Line 7
9	Total Compensation Savings	$ 504,212	$ 228,631	Sum of Lines 3, 8
10	Percent A&G Related	27%	72%	WP Workforce Reduction "18.02 and 18.04 DS A&G Split" tab
11	Jurisdictional Allocator	3.65%	3.65%	1 - Jurisdictional Allocator (Company Schedule WPA-5b)
12	Non Jurisdictional Savings	$ 4,933	$ 6,018	Line 9 * Line 10 * Line 11
13	Jurisdictional Compensational Savings for AIU and AMS	$ 499,279	$ 222,613	Line 9 - Line 12
14	**Total Jurisdictional Compensation Savings**	**$ 721,893**		Total of Line 13 for AIU Amount and AMS Amount
15	Pensions and Benefits (Involuntary)	$ 46,906	$ 31,915	Company Exhibit 51.9 workpaper
16	Pensions and Benefits (Voluntary)	92,302	31,635	Company responses to Staff data requests TEE 18.02
17	Total Pensions and Benefits	$ 139,208	$ 63,550	
18	Non-Jurisdictional Pensions & Benefits	$ 1,362	$ 1,673	Line 17 * Line 10 * Line 11
19	Jurisdictional Pensions & Benefits	$ 137,846	$ 61,877	Line 17 minus line 18
20	**Total Jurisdictional Pensions & Benefits Savings**	**$ 199,723**		Total of Line 19 for AIU Amount and AMS Amount
21	Payroll Tax related to Compensation Savings	$ 38,195	$ 17,030	Line 13 times 7.65%
22	**Total Jurisdictional Payroll Tax**	**$ 55,225**		Total of Line 21 for AIU Amount and AMS Amount
23	Expensed Incentive Compensation per Staff	$ 195		Staff Ex. 15.0, Schedule 15.07, page 2, line 9, col. (g)
24	Expensed Incentive Compensation per Company Direct	1,223		Company Exhibit 51.9 workpaper
25	Percent of Total IC in Revenue Requirement	16%		Line 23 / Line 24

AmerenCILCO Electric
Adjustment to Materials & Supplies
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
1	Accounts Payable Percentage related to Materials & Supplies	10.53%	ICC Staff Exhibit B
2	Materials & Supplies per Company	5,298	Ameren Exhibit 29.1, Schedule 2, Page 1, Line 8, Col. (d)
3	Accounts Payable related to Materials & Supplies	558	Line 1 x Line 2
4	Materials & Supplies Net of Related Accounts Payable	4,740	Line 2 - Line 3
5	Materials & Supplies Inventory per Company	5,298	Ameren Exhibit 29.1, Schedule 2, Page 1, Line 8, Col. (d)
6	**Staff Adjustment**	**$ (558)**	Line 4 - line 5

AmerenCILCO - Gas
Statement of Operating Income with Adjustments
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Company Rebuttal Present (Ex. 30.1, Sch.1)	Staff Adjustments (Appendix B Page 3)	Staff Pro Forma Present (Cols. b+c)	Company Rebuttal Proposed Increase (Ex. 30.1, Sch.1)	Staff Gross Revenue Conversion Factor	Proposed Rates With Staff Adjustments (Cols. d+e+f)	Adjustment To Proposed Increase	Staff Pro Forma Proposed (Cols. g+h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas Service Revenues	$ 72,901	$ -	$ 72,901	$ 6,277	$ 1	$ 79,179	$ (12,124)	$ 67,055
2	Other Revenues	2,177	-	2,177	-	-	2,177	-	2,177
3	Total Operating Revenue	75,078	-	75,078	6,277	1	81,356	(12,124)	69,232
4	Uncollectible Accounts	1,006	-	1,006	84	-	1,090	(162)	928
5	Production Expenses	928	-	928	-	-	928	-	928
6	Storage,Term., and Proc. Expenses	1,666	-	1,666	-	-	1,666	-	1,666
7	Transmission Expenses	761	-	761	-	-	761	-	761
8	Distribution Expenses	17,285	(50)	17,235	-	-	17,235	-	17,235
9	Cust. Accounts,Service & Sales	6,770	(35)	6,735	-	-	6,735	-	6,735
10	Admin. & General Expenses	14,764	(4,836)	9,928	-	-	9,928	-	9,928
11	Depreciation & Amort. Expense	7,565	(39)	7,526	-	-	7,526	-	7,526
12	Taxes Other Than Income	2,877	(120)	2,757	-	-	2,757	-	2,757
13			-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	53,622	(5,080)	48,542	84	-	48,626	(162)	48,464
							-		-
17	State Income Tax	872	559	1,431	452	-	1,883	(873)	1,010
18	Federal Income Tax	3,885	2,482	6,367	2,009	1	8,377	(3,881)	4,496
19		-	-	-	-	-	-	-	-
20	Total Operating Expenses	58,379	(2,039)	56,340	2,545	1	58,886	(4,916)	53,970
21	NET OPERATING INCOME	$ 16,699	$ 2,039	$ 18,738	$ 3,732	$ -	$ 22,470	$ (7,208)	$ 15,262
22	Staff Rate Base (Appendix B, Page 4, Column (d))								$ 191,987
23	Staff Overall Rate of Return (ICC Staff Exhibit 19.0R, Schedule 19.01 CILCO)								7.95%
24	Revenue Change (Col. (i) Line 3 minus Col. (d), Line 3)								$ (5,846)
25	Percentage Revenue Change (Col. (i), Line 24 divided by Col. (d), Line 3)								-7.79%

AmerenCILCO - Gas
Adjustments to Operating Income
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Interest Synchronization (Appendix B Page 6)	Incentive Compensation (St. Ex. 15.0 Sch 15.07 CILCO-G)	Employee Benefits (St. Ex. 15.0 Sch 15.09 CILCO-G)	Workforce Reduction (Appendix B Page 12)	Pro Forma Plant Additions (St. Ex. 16.0 Sch 16.01 CILCO-G Corrected)	Transportation Fuel Costs (St. Ex.17.0 Sch 17.01 CILCO-G)	(Source)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas Service Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-			-	-
5	Production Expenses	-	-	-	-	-	-	-	-
6	Storage,Term., and Proc. Expenses	-	-	-	-	-	-	-	-
7	Transmission Expenses	-	-	-	-	-	-	-	-
8	Distribution Expenses	-	-		-	-	(27)		(27)
9	Cust. Accounts,Service & Sales	-	-	-	-	-	-		-
10	Admin. & General Expenses	-	(619)	(3,043)	(1,067)				(4,729)
11	Depreciation & Amort. Expense	-	(5)	-	-	(34)			(39)
12	Taxes Other Than Income	-	(59)		(61)		-	-	(120)
13	-	-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	-	(683)	(3,043)	(1,128)	(34)	(27)	-	(4,915)
								-	
17	State Income Tax	188	50	222	82	2	2	-	546
18	Federal Income Tax	835	222	987	366	11	9	-	2,430
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	1,023	(411)	(1,834)	(680)	(21)	(16)	-	(1,939)
21	NET OPERATING INCOME	$ (1,023)	$ 411	$ 1,834	$ 680	$ 21	$ 16	$ -	$ 1,939

AmerenCILCO - Gas
Adjustments to Operating Income
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Sulfatreat Change Out Adj (St. Ex.17.0 Sch 17.03 CILCO-G)	(Source)	Industry Association Dues (St. Ex.18.0R Sch 18.03 CILCO-G)	Customer Service & Info. Expense (St. Ex. 18.0R Sch 18.04 CILCO-G)	Demonstrating & Selling (St. Ex. 18.0R Sch 18.06 CILCO-G)	(Source)	Total Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas Service Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Production Expenses	-	-	-	-	-	-	-	-
6	Storage,Term., and Proc. Expenses	-	-		-	-	-	-	-
7	Transmission Expenses	-	-	-	-	-	-	-	-
8	Distribution Expenses	(27)	(23)	-	-	-	-	-	(50)
9	Cust. Accounts,Service & Sales	-	-	-	-	(35)	-	-	(35)
10	Admin. & General Expenses	(4,729)	-	-	(97)		(10)	-	(4,836)
11	Depreciation & Amort. Expense	(39)	-	-	-		-	-	(39)
12	Taxes Other Than Income	(120)	-	-	-	-	-	-	(120)
13	-	-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	(4,915)	(23)	-	(97)	(35)	(10)	-	(5,080)
17	State Income Tax	546	2	-	7	3	1	-	559
18	Federal Income Tax	2,430	7	-	31	11	3	-	2,482
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	(1,939)	(14)	-	(59)	(21)	(6)	-	(2,039)
21	NET OPERATING INCOME	$ 1,939	$ 14	$ -	$ 59	$ 21	$ 6	$ -	$ 2,039

AmerenCILCO - Gas
Rate Base
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Company Rebuttal Rate Base (Ex. 30.1, Sch.2)	Staff Adjustments (Appendix B Page 5)	Staff Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Plant in Service	$ 536,076	$ (2,273)	$ 533,803
2	Accumulated Depreciation	(356,292)	(506)	(356,798)
3	-	-	-	-
4	Net Plant	179,784	(2,779)	177,005
5	Additions to Rate Base			
6	Cash Working Capital	7,478	(2,175)	5,303
7	Materials & Supplies Inventory	48,046	(4,946)	43,100
8	CWIP Not Subject to AFUDC	12	-	12
9	-	-	-	-
10	-	-	-	-
11	-	-	-	-
12	-	-	-	-
13	-	-	-	-
14	-	-	-	-
15	-	-	-	-
16	Deductions From Rate Base			
17	Customer Advances	(3,535)	-	(3,535)
18	Accumulated Deferred Income Taxes	(10,828)	143	(10,685)
19	Customer Deposits	(3,678)	-	(3,678)
20	Accrued OPEB Liability	-	(15,535)	(15,535)
21	-	-	-	-
22	-	-	-	-
23	Rate Base	$ 217,279	$ (25,292)	$ 191,987

AmerenCILCO - Gas
Adjustments to Rate Base
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Incentive Compensation (St. Ex. 15.0 Sch 15.07 CILCO-G)	Cash Working Capital (Appendix B Page 8)	Pro Forma Plant Additions (St. Ex. 16.0 Sch 16.01 CILCO-G Corrected)	Materials & Supplies (Appendix B Page 14)	Accrued OPEB Liabilities (AG/CUB Exhibit 2.1)	Sulfatreat Change Out Adj (St. Ex.17.0 Sch 17.03 CILCO-G)	(Source)	Total Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Plant in Service	$ (154)	$ -	$ (2,142)	$ -	$ -	$ 23	$ -	$ (2,273)
2	Accumulated Depreciation	(5)	-	(501)	-	-	-	-	$ (506)
3	-	-	-	-	-	-	-	-	$ -
4	Net Plant	(159)	-	(2,643)	-	-	23	-	$ (2,779)
	-								
5	Additions to Rate Base								$ -
6	Cash Working Capital	-	(2,175)	-	-		-	-	$ (2,175)
7	Materials & Supplies Inventory	-		-	(4,946)	-	-	-	$ (4,946)
8	CWIP Not Subject to AFUDC	-	-	-	-	-	-	-	$ -
9	-	-	-	-	-	-	-	-	$ -
10	-	-	-	-	-	-	-	-	$ -
11	-	-	-	-	-	-	-	-	$ -
12	-	-	-	-	-	-	-	-	$ -
13	-	-	-	-	-	-	-	-	$ -
14	-	-	-	-	-	-	-	-	$ -
15	-	-	-	-	-	-	-	-	$ -
16	Deductions From Rate Base	-	-	-	-	-	-	-	$ -
17	Customer Advances	-	-	-	-	-	-	-	$ -
18	Accumulated Deferred Income Taxes	3	-	145	-	-	(5)	-	$ 143
19	Customer Deposits	-	-		-	-	-	-	$ -
20	Accrued OPEB Liability	-	-	-	-	(15,535)	-	-	$ (15,535)
21	-	-	-	-	-	-	-	-	$ -
22	-	-	-	-	-	-	-	-	$ -
	-								
23	Rate Base	$ (156)	$ (2,175)	$ (2,498)	$ (4,946)	$ (15,535)	$ 18	$ -	$ (25,292)

AmerenCILCO - Gas
Interest Synchronization Adjustment
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Amount	
	(a)	(b)	
1	Rate Base	$ 191,987	(1)
2	Weighted Cost of Debt	3.60%	(2)
3	Synchronized Interest Per Staff	6,912	
4	Company Interest Expense	9,484	(3)
5	Increase (Decrease) in Interest Expense	(2,573)	
6	Increase (Decrease) in State Income Tax Expense		
7	at 7.300%	$ 188	
8	Increase (Decrease) in Federal Income Tax Expense		
9	at 35.000%	$ 835	

(1) Source: Appendix B, Page 4, Column (d).
(2) Source: ICC Staff Exhibit 19.0R, Schedule 19.01 CILCO.
(3) Source: Ameren Exhibit 30.1, Schedule 3

AmerenCILCO - Gas
Gross Revenue Conversion Factor
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(a)	(b)	(c)	(d)
1	Revenues		1.000000	
2	Uncollectibles	1.3398%	0.013398	
3	State Taxable Income		0.986602	1.000000
4	State Income Tax	7.3000%	0.072022	0.073000
5	Federal Taxable Income		0.914580	0.927000
6	Federal Income Tax	35.0000%	0.320103	0.324450
7	Operating Income		0.594477	0.602550
8	Gross Revenue Conversion Factor Per Staff		1.682151	1.659613

Ameren/CILCO Gas
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Description (a)	Amount (b)	Source (c)
1	Cash Working Capital per Staff	$ 5,303	Appendix B, Page 9, Column (e), Line 23
2	Cash Working Capital per Company	7,478	Ameren Ex. 30.1, Schedule 2, page 3, column (G), line 31
3	Difference -- Staff Adjustment	$ (2,175)	Line 1 less Line 2

Ameren/CILCO Gas
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Item (a)	Amount (b)	Lag (Lead) (c)	CWC Factor (d) (c/365)	CWC Requirement (e) (b*d)	Column C Source (f)
1	Revenues	$ 336,092	46.530	0.12748	$ 42,845	Appendix B, Page 10, Column b, Line 6
2	Pass-through Taxes	10,295	0.000	0.00000	-	Line 11 + Line 13 + Line 14 + Line 16 below
3	Total Receipts	$ 346,387				Line 1 + Line 2
4	Employee Benefits	$ 1,678	(17.570)	(0.04814)	(81)	Appendix B, Page 11, Column b, Line 15
5	Payroll	13,442	(12.920)	(0.03540)	(476)	Appendix B, Page 11, Column b, Line 5
6	PGA Purchases	283,665	(39.420)	(0.10800)	(30,636)	Company Schedule B-8, Column F, Line 3
7	Other Operations and Maintenance	22,133	(51.070)	(0.13992)	(3,097)	Appendix B, Page 10, Column b, Line 16
8	FICA	500	(14.740)	(0.04038)	(20)	Appendix B, Page 11, Column b, Line 11
9	Federal Unemployment Tax	7	(76.380)	(0.20926)	(1)	Company Schedule C-18, Column G, Line 3
10	State Unemployment Tax	47	(76.380)	(0.20926)	(10)	Company Schedule C-18, Column G, Line 7
11	ICC Gas Revenue Tax	342	24.470	0.06704	23	Company Schedule C-18, Column E, Line 9
12	Invested Capital Tax	1,383	(30.130)	(0.08255)	(114)	Company Schedule C-18, Column G, Line 11
13	Municipal Utility Tax	804	(45.630)	(0.12501)	(101)	Company Schedule C-18, Column E, Line 15
14	Energy Assistance Tax	1,975	(42.280)	(0.11584)	(229)	Company Schedule C-18, Column E, Line 10
15	Corporation Franchise Tax	141	(191.530)	(0.52474)	(74)	Company Schedule C-18, Column G, Line 8
16	Illinois Gas Use and Gas Revenue Tax	7,174	(29.420)	(0.08060)	(578)	Company Schedule C-18, Column E, Line 6
17	Property/Real Estate Tax	117	(392.700)	(1.07589)	(126)	Company Schedule C-18, Column G, Line 14
18	Interest Expense	6,374	(91.250)	(0.25000)	(1,593)	Appendix B, Page 6, Line 3 - line 19
19	Bank Facility Fees	538	97.650	0.26753	144	Appendix B, Page 4, Column d, line 23 times Bank Facility Fees Weighted Component Sched. 19.01
20	Federal Income Tax	4,496	(38.000)	(0.10411)	(468)	Appendix B, page 1, Column i, Line 18
21	State Income Tax	1,010	(38.000)	(0.10411)	(105)	Appendix B, Page 1, Column i, Line 17
22	Total Outlays	$ 345,826				Sum of Lines 4 through 21
23	Cash Working Capital per Staff				$ 5,303	Sum of Lines 1 through 21

Ameren/CILCO Gas
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Revenues		Amount	Source
	(a)		(b)	(c)
1	Total Operating Revenues	$	69,232	Appendix B, page 1, Column i, Line 3
2	PGA Purchases		283,665	Company Schedule B-8, Column F, Line 3
3	Uncollectible Accounts		(928)	Appendix B, Page 1, Column i, Line 4
4	Depreciation & Amortization		(7,526)	Appendix B, Page 1, Column i, Line 11
5	Return on Equity		(8,351)	Line 9 below
6	Total Revenues for CWC calculation	$	336,092	Sum of Lines 1 through 5
7	Total Rate Base	$	191,987	Appendix B, Page 4, Column d, Line 23
8	Weighted Cost of Capital		4.35%	ICC Staff Exhibit 19.0R, Schedule 19.01 CILCO
9	Return on Equity	$	8,351	Line 7 times Line 8
10	Operating Expense Before Income Taxes	$	48,464	Appendix B, Page 1, Column i, Line 16
11	Employee Benefits Expense		(1,678)	Appendix B, Page 11, Column b, Line 15
12	Payroll Expense		(13,442)	Appendix B, Page 11, Column b, Line 5
13	Uncollectible Accounts		(928)	Appendix B, Page 1, Column i, Line 4
14	Depreciation & Amortization		(7,526)	Appendix B, Page 1, Column i, Line 11
15	Taxes Other Than Income		(2,757)	Appendix B, Page 1, Column i, Line 12
16	Other Operations & Maintenance for CWC Calculation	$	22,133	Sum of Lines 10 through 15

Ameren/CILCO Gas
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Description (a)	Amount (b)	Source (c)
1	Direct Payroll per Company Filing	$ 15,333	Company Schedule B-8, Column F, Line 2
2	Staff Labor Adjustment	(474)	ICC Staff Ex. 1.0, Sch. 1.09 CILCO-G, Line 3
3	Adjustment for Workforce Reduction	(798)	Appendix B, Page 12, Line 3
4	Adjustment for Incentive Compensation	(619)	ICC Staff Ex. 15.0, Sch. 15.07 CILCO-G, Page 1, Line 6
5	Direct Payroll per Staff	$ 13,442	Sum of Lines 1 through 4
6	FICA Tax per Company Filing	$ 671	Company Schedule C-18, Column G, Line 2
7	Labor Adjustment	(36)	ICC Staff Ex. 1.0, Sch. 1.09 CILCO-G, Line 5
8	Incentive Compensation Adjustment	(59)	ICC Staff Ex. 15.0, Sch. 15.07 CILCO-G, page 1, Line 20
9	Adjustment for Workforce Reduction	(61)	Appendix B, Page 12, Line 7
10	Company FICA Correction Adjustment	(14)	ICC Staff Ex. 1.0, Sch. 1.11 CILCO-G, Line 13
11	FICA Tax per Staff	$ 500	Sum of Lines 6 through 10
12	Employee Benefits per Company Filing	$ 4,990	Company Schedule B-8, Column F, Line 1
13	Adjustment for Workforce Reduction	(269)	Appendix B, Page 12, Line 6
14	Staff Adjustment	(3,043)	ICC Staff Ex. 15.0, Sch. 15.09 CILCO-G, Line 9
15	Employee Benefits per Staff	$ 1,678	Sum of Lines 12 through 14

AmerenCILCO - Gas
Adjustment for Workforce Reduction
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(d)
1	Staff Proposed Compensation Savings	$ (798)	Appendix B, Page 13, line 10
2	Company CompensationSavings Rebuttal	-	
3	**Staff Proposed Adjustment**	$ (798)	
4	Staff Pension & Benefits Proposed Savings	$ (269)	Appendix B, Page 13, line 15
5	Company Pension & Benefits Savings Rebuttal	-	
6	**Staff Proposed Adjustment**	$ (269)	
7	**Taxes Other Than Income Adjustment**	$ (61)	Appendix B, Page 13, line 11

AmerenCILCO - Gas
Adjustment for Workforce Reduction
For the Test Year Ending 12/31/2008
(In Dollars)

Line No.	Description (a)	AIU Amount (b)	AMS Amount (c)	Source (d)
1	Salaries (Involuntary)	$ 201,904	$ 83,726	Company Exhibit 51.9 workpaper
2	Salaries (Voluntary)	412,446	83,001	Company responses to Staff data requests TEE 18.02
3	Total Salaries	$ 614,349	$ 166,727	
4	Incentive Compensation (Involuntary)	$ 17,363	$ 8,666	Company Exhibit 51.9 workpaper
5	Incentive Compensation (Voluntary)	64,487	12,545	Company responses to Staff data requests TEE 18.02
6	Total Incentive Compensation	$ 81,850	$ 21,211	
7	Percent of Total IC in Revenue Requirement	16%	16%	Line 18
8	Total Incentive Compensation	$ 13,061	$ 3,385	Line 9 * Line 10
9	Jurisdictional Compensation Savings for AIU and AMS	$ 627,411	$ 170,112	Sum of Lines 3, 8
10	**Total Jurisdictional Compensation Savings**	**$ 797,523**		Total of Line 9 for AIU Amount and AMS Amount
11	**Payroll related to Net Savings**	**$ 61,011**		Line 10 times 7.65%
12	Pensions and Benefits (Involuntary)	$ 69,475	$ 28,810	Company Exhibit 51.9 workpaper
13	Pensions and Benefits (Voluntary)	141,922	28,561	Company responses to Staff data requests TEE 18.02
14	Total Pensions and Benefits	$ 211,398	$ 57,371	
15	**Total Jurisdictional Pension & Benefits Savings**	**$ 268,768**		
16	Expensed Incentive Compensation per Staff	$ 164		Staff Ex. 15.0, Schedule 15.07, page 2, line 9, col. (g)
17	Expensed Incentive Compensation per Company Direct	$ 1,028		Company Exhibit 51.9 workpaper
18	Percent of Total IC in Revenue Requirement	16%		Line 16 / Line 17

AmerenCILCO Gas
Adjustment to Materials & Supplies (Including Gas in Storage)
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
1	Materials & Supplies (Including Gas in Storage) per Staff	$ 43,100	Appendix B, Page 15, Line 9, Col. (b)
2	Materials & Supplies (Including Gas in Storage) per Company	48,046	Ameren Exhibit 30.1, Schedule 2, page 1, Line 8, Col. (d)
3	**Staff Adjustment**	**$ (4,946)**	Line 1 - line 2

AmerenCILCO Gas
Adjustment to Materials & Supplies (Including Gas in Storage)
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
	General Materials and Supplies		
1	Accounts Payable Percentage related to Materials & Supplies	10.53%	ICC Staff Exhibit B
2	General materials & Supplies per Company	2,169	Ameren Exhibit 30.8 CIL G, Page 1, Line 1, Col. (b)
3	Accounts Payable related to Materials & Supplies	228	Line 1 x Line 2
4	General Materials & Supplies Net of Related Accounts Payable	1,941	Line 2 - Line 3
	Gas in Storage		
5	Accounts Payable Percentage related to Gas in Storage	6.63%	ICC Staff Exhibit B
6	13-Month Average of Gas in Storage per Staff	44,082	Appendix B, Page 15, Column (b), Line 3
7	Accounts Payable related to Gas in Storage	2,923	Line 5 x Line 6
8	Gas in Storage Net of Related Accounts Payable	41,159	Line 6 - Line 7
9	Total Materials & Supplies (Including Gas in Storage) per Staff	43,100	Line 4 + Line 8

AmerenCILCO Gas
Adjustment to Materials & Supplies (Including Gas in Storage)
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
1	13-month Average Balance Gas in Storage per Company	$ 45,877	Ameren Exhibit 30.8 CIL G, Page 1, Line 2, Col. (b)
2	Adjustment to 13-month Average Balance Gas in Storage	(1,795)	ICC Staff Exhibit 25.0, Schedule 25.01 CILCO-G
3	13-month Average Balance Gas in Storage per Staff	$ 44,082	Line 1 + line 2

AmerenCIPS - Electric
Statement of Operating Income with Adjustments
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Company Rebuttal Present (Ex. 29.2, Sch. 1)	Staff Adjustments (Appendix C Page 4)	Staff Pro Forma Present (Cols. b+c)	Company Rebuttal Proposed Increase (Ex. 29.2, Sch. 1)	Staff Gross Revenue Conversion Factor	Proposed Rates With Staff Adjustments (Cols. d+e+f)	Adjustment To Proposed Increase	Staff Pro Forma Proposed (Cols. g+h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Electric Operating Revenues	$ 220,749	$ -	$ 220,749	$ 41,377	$ -	$ 262,126	$ (20,430)	$ 241,696
2	Other Revenues	14,628	-	14,628	-	-	14,628	-	14,628
3	Total Operating Revenue	$ 235,377	$ -	$ 235,377	$ 41,377	$ -	$ 276,754	$ (20,430)	$ 256,324
4	Uncollectible Accounts	$ 2,159	$ -	$ 2,159	$ 380	$ -	$ 2,539	$ (187)	$ 2,352
5	Distribution Expenses	69,108	(3,442)	65,666	-	-	65,666	-	65,666
6	Customer Accounts Expense	15,564	(30)	15,534	-	-	15,534	-	15,534
7	Admin. & General Expenses	48,140	(6,811)	41,329	-	-	41,329	-	41,329
8	Depreciation & Amort. Expense	53,033	(404)	52,629	-	-	52,629	-	52,629
9	Taxes Other Than Income	20,096	(2,280)	17,816	-	-	17,816	-	17,816
10			-	-	-	-	-	-	-
11			-	-	-	-	-	-	-
12			-	-	-	-	-	-	-
13			-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	$ 208,100	$ (12,967)	$ 195,133	$ 380	$ -	$ 195,513	$ (187)	$ 195,326
17	State Income Tax	827	1,008	1,835	2,993	-	4,828	(1,478)	3,350
18	Federal Income Tax	3,654	4,475	8,129	13,301	1	21,431	(6,568)	14,863
19		-	-	-	-	-	-	-	-
20	Total Operating Expenses	$ 212,581	$ (7,484)	$ 205,097	$ 16,674	$ 1	$ 221,772	$ (8,233)	$ 213,539
21	NET OPERATING INCOME	$ 22,796	$ 7,484	$ 30,280	$ 24,703	$ (1)	$ 54,982	$ (12,197)	$ 42,785
22	Staff Rate Base (Appendix C, Page 5, Column (d))								$ 530,832
23	Staff Overall Rate of Return (ICC Staff Exhibit 19.0R, Schedule 19.01 CIPS)								8.06%
24	Revenue Change (Col. (i) Line 3 minus Col. (d), Line 3)								$ 20,947
25	Percentage Revenue Change (Col. (i), Line 24 divided by Col. (d), Line 3)								8.90%

AmerenCIPS - Electric
Adjustments to Operating Income
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Interest Synchronization (Appendix C Page 7)	Incentive Compensation (St. Ex. 15.0 Sch 15.07 CIPS-E)	Employee Benefits (St. Ex. 15.0 Sch 15.09 CIPS-E)	Workforce Reduction (Appendix C Page 13)	Production Retiree Expense (St. Ex. 15.0 Sch 15.11 CIPS-E)	Electric Distribution Tax (St. Ex. 15.0 Sch 15.12 CIPS-E)	(Source)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Electric Operating Revenues	-	-	-	-	-	-	-	-
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-			-	-
5	Distribution Expenses	-	-	-	-	-	-	-	-
6	Customer Accounts Expense	-	-	-	-	-	-	-	-
7	Admin. & General Expenses	-	(1,602)	(4,128)	(846)	64			(6,512)
8	Depreciation & Amort. Expense	-	(17)	-		-	-	-	(17)
9	Taxes Other Than Income	-	(160)	-	(53)	-	(2,067)	-	(2,280)
10	-	-	-	-	-	-		-	-
11	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	-	(1,779)	(4,128)	(899)	64	(2,067)	-	(8,809)
								-	
17	State Income Tax	60	130	301	66	(5)	151	-	703
18	Federal Income Tax	266	577	1,339	292	(21)	671	-	3,124
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	326	(1,072)	(2,488)	(541)	38	(1,245)	-	(4,982)
21	NET OPERATING INCOME	(326)	1,072	2,488	541	(38)	1,245	-	4,982

AmerenCIPS - Electric
Adjustments to Operating Income
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	(Source)	Pro Forma Plant Additions (St. Ex. 16.0 Sch 16.01 IP-E Corrected)	NESC Adjustment (St. Ex. 16.0 Sch 16.03 CIPS-E)	Substation Relocation (St. Ex. 16.0 Sch 16.04 CIPS-E)	Transportation Fuel Costs (St. Ex. 17.0 Sch 17.01 CIPS-E)	Tree Trimming (St. Ex. 17.0 Sch 17.02 CIPS-E)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Distribution Expenses	-	-	-	(474)	-	(494)	(2,474)	(3,442)
6	Customer Accounts Expense	-	-	-	-	-	-	-	-
7	Admin. & General Expenses	(6,512)	-		-		-		(6,512)
8	Depreciation & Amort. Expense	(17)		(302)	(9)	(76)	-	-	(404)
9	Taxes Other Than Income	(2,280)	-	-	-	-	-	-	(2,280)
10	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	(8,809)	-	(302)	(483)	(76)	(494)	(2,474)	(12,638)
17	State Income Tax	703	-	22	35	6	36	181	983
18	Federal Income Tax	3,124	-	98	157	25	160	803	4,367
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	(4,982)	-	(182)	(291)	(45)	(298)	(1,490)	(7,288)
21	NET OPERATING INCOME	$ 4,982	$ -	$ 182	$ 291	$ 45	$ 298	$ 1,490	$ 7,288

AmerenCIPS - Electric
Adjustments to Operating Income
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Lobbying Expense (St. Ex. 18.0R Sch 18.01 CIPS-E)	Industry Association Dues (St. Ex. 18.0R Sch 18.03 CIPS-E)	Customer Service & Info. Expense (St. Ex. 18.0R Sch 18.04 CIPS-E)	Demonstrating & Selling (St. Ex. 18.0R Sch 18.06 CIPS-E)	(Source)	(Source)	Total Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Distribution Expenses	(3,442)			-	-	-	-	(3,442)
6	Customer Accounts Expense	-	-	-	(30)	-	-	-	(30)
7	Admin. & General Expenses	(6,512)	(8)	(147)	-	(144)			(6,811)
8	Depreciation & Amort. Expense	(404)	-	-	-	-	-	-	(404)
9	Taxes Other Than Income	(2,280)	-	-	-	-	-	-	(2,280)
10	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	(12,638)	(8)	(147)	(30)	(144)	-	-	(12,967)
17	State Income Tax	983	1	11	2	11	-	-	1,008
18	Federal Income Tax	4,367	3	48	10	47	-	-	4,475
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	(7,288)	(4)	(88)	(18)	(86)	-	-	(7,484)
21	NET OPERATING INCOME	$ 7,288	$ 4	$ 88	$ 18	$ 86	$ -	$ -	$ 7,484

AmerenCIPS - Electric
Rate Base
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Company Rebuttal Rate Base (Ex. 29.2, Sch. 2)	Staff Adjustments (Appendix C Page 6)	Staff Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Plant in Service	$ 1,404,840	$ (10,098)	$ 1,394,742
2	Accumulated Depreciation	(746,880)	(561)	(747,441)
3	-	-	-	-
4	Net Plant	657,960	(10,659)	647,301
5	Additions to Rate Base			
6	Cash Working Capital	2,765	(1,280)	1,485
7	Materials & Supplies Inventory	11,155	(1,175)	9,980
8	CWIP Not Subject to AFUDC	140	-	140
9	Plant Held for Future Use	376	-	376
10	-	-	-	-
11	-	-	-	-
12	-	-	-	-
13	-	-	-	-
14	-	-	-	-
15	-	-	-	-
16	Deductions From Rate Base			
17	Customer Advances	(3,345)	-	(3,345)
18	Accumulated Deferred Income Taxes	(113,255)	423	(112,832)
19	Customer Deposits	(8,500)	-	(8,500)
20	Accrued OPEB Liability	-	(3,774)	(3,774)
21	-	-	-	-
22	-	-	-	-
23	Rate Base	$ 547,296	$ (16,464)	$ 530,832

AmerenCIPS - Electric
Adjustments to Rate Base
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Incentive Compensation (St. Ex. 15.0 Sch 15.07 CIPS-E)	Cash Working Capital (Appendix C Page 9)	Pro Forma Plant Additions (St. Ex. 16.0 Sch 16.01 CIPS-E Corrected)	NESC Adjustment (St. Ex. 16.0 Sch 16.03 CIPS-E)	Substation Relocation (St. Ex. 16.0 Sch 16.04 CIPS-E)	Materials & Supplies (Appendix C Page 15)	Accrued OPEB Liabilities (AG/CUB Exhibit 2.1)	Total Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Plant in Service	$ (490)	$ -	$ (7,406)	$ (202)	$ (2,000)	$ -	$ -	$ (10,098)
2	Accumulated Depreciation	(17)	-	(1,609)	2	1,063	-	-	(561)
3	-	-	-	-	-	-	-	-	-
4	Net Plant	(507)	-	(9,015)	(200)	(937)	-	-	(10,659)
	-								
5	Additions to Rate Base								-
6	Cash Working Capital	-	(1,280)	-	-	-	-		(1,280)
7	Materials & Supplies Inventory	-		-	-	-	(1,175)	-	(1,175)
8	CWIP Not Subject to AFUDC	-	-	-	-		-	-	-
9	Plant Held for Future Use	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-
16	Deductions From Rate Base	-	-	-	-	-	-	-	-
17	Customer Advances	-	-	-	-	-	-	-	-
18	Accumulated Deferred Income Taxes	10	-	210	42	161	-	-	423
19	Customer Deposits	-	-	-	-	-	-	-	-
20	Accrued OPEB Liability	-	-	-	-	-	-	(3,774)	(3,774)
21		-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-
	-								
23	Rate Base	$ (497)	$ (1,280)	$ (8,805)	$ (158)	$ (776)	$ (1,175)	$ (3,774)	$ (16,464)

AmerenCIPS - Electric
Interest Synchronization Adjustment
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Amount	
	(a)	(b)	
1	Gross Plant in Service	$ 530,832	(1)
2	Weighted Cost of Debt	2.8600%	(2)
3	Synchronized Interest Per Staff	15,182	
4	Company Interest Expense	16,003	(3)
5	Increase (Decrease) in Interest Expense	(821)	
6	Increase (Decrease) in State Income Tax Expense		
7	at 7.300%	$ 60	
8	Increase (Decrease) in Federal Income Tax Expense		
9	at 35.000%	$ 266	

(1) Source: Appendix C, Page 5, Column(d) Line 23.
(2) Source: ICC Staff Exhibit 19.0R, Schedule 19.01 CIPS.
(3) Source: Ameren Exhibit 29.2, Schedule 3

AmerenCIPS - Electric
Gross Revenue Conversion Factor
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(a)	(b)	(c)	(d)
1	Revenues		1.000000	
2	Uncollectibles	0.9174%	0.009174	
3	State Taxable Income		0.990826	1.000000
4	State Income Tax	7.3000%	0.072330	0.073000
5	Federal Taxable Income		0.918496	0.927000
6	Federal Income Tax	35.0000%	0.321474	0.324450
7	Operating Income		0.597022	0.602550
8	Gross Revenue Conversion Factor Per Staff		1.674980	1.659613

Ameren/CIPS Electric
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Description (a)	Amount (b)	Source (c)
1	Cash Working Capital per Staff	$ 1,485	Appendix C, Page 10, Column e, Line 22
2	Cash Working Capital per Company	2,765	Ameren Exhibit 29.2, Schedule 2, page 4, column (G), line 24
3	Difference -- Staff Adjustment	$ (1,280)	Line 1 less Line 2

Ameren/CIPS Electric
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Item (a)	Amount (b)	Lag (Lead) (c)	CWC Factor (d) (c/365)	CWC Requirement (e) (b*d)	Column C Source (f)
1	Revenues	$ 173,739	46.550	0.12753	$ 22,158	Appendix C, Page 11, Column b, Line 7
2	Pass-through Taxes	4,878	0.000	0.00000	-	Line 12 + Line 13 below
3	Total Receipts	$ 178,617				Line 1 + Line 2
4	Employee Benefits	$ 8,544	(17.570)	(0.04814)	(411)	Appendix C, Page 12, Column b, Line 16
5	Payroll	44,813	(12.920)	(0.03540)	(1,586)	Appendix C, Page 12, Column b, Line 5
6	Purchased Power	-	(18.080)	(0.04953)	-	
7	Other Operations and Maintenance	69,172	(51.070)	(0.13992)	(9,678)	Appendix C, Page 11, Column b, Line 17
8	FICA	1,907	(14.740)	(0.04038)	(77)	Appendix C, Page 12, Column b, Line 11
9	Federal Unemployment Tax	18	(76.380)	(0.20926)	(4)	Company Schedule C-18, Column J, Line 3
10	State Unemployment Tax	28	(76.380)	(0.20926)	(6)	Company Schedule C-18, Column J, Line 7
11	Electricity Distribution Tax	14,022	(30.130)	(0.08255)	(1,157)	ICC Staff Ex. 15.0, Sch.15.12 CIPS-E, Column b, Line 1
12	Federal Excise Tax	1	(45.630)	(0.12501)	-	Company Schedule C-18, Column H, Line 4
13	Energy Assistance Tax	4,877	(42.280)	(0.11584)	(565)	Company Schedule C-18, Column H, Line 10
14	Corporation Franchise Tax	136	(191.530)	(0.52474)	(71)	Company Schedule C-18, Column J, Line 9
15	Gross Receipts/Municipal Utility Ta	36	(45.630)	(0.12501)	(5)	Company Schedule C-18, Column H: Line 12 + Line 16
16	Property/Real Estate Tax	1,705	(392.700)	(1.07589)	(1,834)	Company Schedule C-18, Column J, Line 15
17	Interest Expense	14,386	(91.250)	(0.25000)	(3,596)	Appendix C, Page 7, Line 3 - line 18
18	Bank Facility Fees	796	97.650	0.26753	213	Appendix C, Page 5, Column d, line 23 times Bank Facility Fees Weighted Component Sched. 19.01
19	Federal Income Tax	14,863	(38.000)	(0.10411)	(1,547)	Appendix C, Page 1, Column i, Line 18
20	State Income Tax	3,350	(38.000)	(0.10411)	(349)	Appendix C, Page 1, Column i, Line 17
21	Total Outlays	$ 178,654				Sum of Lines 4 through 20
22	Cash Working Capital per Staff				$ 1,485	Sum of Lines 1 through 20

Ameren/CIPS Electric
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Revenues (a)	Amount (b)	Source (c)
1	Total Operating Revenues	$ 256,324	Appendix C, Page 1, Column i, Line 3
2	Purchased Power	-	
3	Uncollectible Accounts	(2,352)	Appendix C, Page 1, Column i, Line 4
4	Depreciation & Amortization	(52,629)	Appendix C, Page 1, Column i, Line 8
5	Return on Equity	(27,603)	Line 10 below
6		-	
7	Total Revenues for CWC calculation	$ 173,739	Sum of Lines 1 through 6
8	Total Rate Base	$ 530,832	Appendix C, Page 5, Column d, Line 23
9	Weighted Cost of Capital	5.20%	ICC Staff Ex. 19.0R, Schedule 19.01 CIPS
10	Return on Equity	$ 27,603	Line 8 times Line 9
11	Operating Expense Before Income Taxes	$ 195,326	Appendix C, Page 1, Column i, Line 16
12	Employee Benefits Expense	(8,544)	Appendix C, Page 12, Column B, Line 16
13	Payroll Expense	(44,813)	Appendix C, Page 12, Column B, Line 5
14	Uncollectible Accounts	(2,352)	Appendix C, Page 1, Column i, Line 4
15	Depreciation & Amortization	(52,629)	Appendix C, Page 1, Column i, Line 8
16	Taxes Other Than Income	(17,816)	Appendix C, Page 1, Column i, Line 9
17	Other Operations & Maintenance for CWC Calculation	$ 69,172	Sum of Lines 11 through 16

Ameren/CIPS Electric
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Description (a)		Amount (b)	Source (c)
1	Direct Payroll per Company Filing	$	48,423	Company Schedule B-8, Column F, Line 2
2	Staff Labor Adjustment		(1,312)	ICC Staff Ex. 1.0, Sch. 1.09 CIPS-E, Line 3
3	Adjustment for Workforce Reduction		(696)	Appendix C, Page 13, Line 3
4	Adjustment for Incentive Compensation		(1,602)	ICC Staff Ex. 15.0, Sch. 15.07 CIPS-E, Page 1, Line 6
5	Direct Payroll per Staff	$	44,813	Sum of Lines 1 through 4
6	FICA Tax per Company Filing	$	2,220	Company Schedule C-18, Column J, Line 2
7	Labor Adjustment		(100)	ICC Staff Ex. 1.0, Sch. 1.09 CIPS-E, Line 5
8	Incentive Compensation Adjustment		(160)	ICC Staff Ex. 15.0, Sch. 15.07 CIPS-E, Page 1, Line 20
9	Adjustment for Workforce Reduction		(53)	Appendix C, Page 13, Line 7
10	Company FICA Correction Adjustment		-	ICC Staff Ex. 1.0, Sch. 1.11 CIPS-E, Line 13
11	FICA Tax per Staff	$	1,907	Sum of Lines 6 through 10
12	Employee Benefits per Company Filing	$	12,758	Company Schedule B-8, Column F, Line 1
13	Staff Adjustment for Employee Benefits		(4,128)	ICC Staff Ex. 15.0, Sch. 15.09 CIPS-E, Line 7
14	Adjustment for Workforce Reduction		(150)	Appendix C, Page 13, Line 6
15	Staff Adjustment for Retiree Benefits		64	ICC Staff Ex. 15.0, Sch. 15.11 CIPS-E, Line 5
16	Employee Benefits per Staff	$	8,544	Sum of Lines 12 through 15

AmerenCIPS - Electric
Adjustment for Workforce Reduction
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(d)
1	Staff Proposed Compensation Savings	$ (696)	Appendix C, Page 14 line 14
2	Company CompensationSavings Rebuttal	-	
3	**Staff Proposed Adjustment**	$ (696)	
4	Staff Pension & Benefits Proposed Savings	$ (150)	Appendix C, Page 14 line 20
5	Company Pension & Benefits Savings Rebuttal	-	
6	**Staff Proposed Adjustment**	$ (150)	
7	**Taxes Other Than Income Adjustment**	$ (53)	Appendix C, Page 14, line 22

AmerenCIPS - Electric
Adjustment for Workforce Reduction
For the Test Year Ending 12/31/2008
(in Dollars)

Line No.	Description	AIU Amount	AMS Amount	Source
	(a)	(b)	(c)	(d)
1	Salaries (Involuntary)	$ 59,378	$ 138,480	Company Exhibit 51.9 workpaper
2	Salaries (Voluntary)	224,021	279,859	Company responses to Staff data requests TEE 18.02
3	Total Salaries	$ 283,399	$ 418,339	
4	Incentive Compensation (Involuntary)	$ 4,750	$ 16,417	Company Exhibit 51.9 workpaper
5	Incentive Compensation (Voluntary)	15,882	44,150	Company responses to Staff data requests TEE 18.02
6	Total Incentive Compensation	$ 20,632	$ 60,567	
7	Percent of Total IC in Revenue Requirement	19%	19%	Line 25
8	Total Incentive Compensation	$ 3,858	$ 11,325	Line 6 * Line 7
9	Total Compensation Savings	$ 287,257	$ 429,664	Sum of Lines 3, 8
10	Percent A&G Related	27%	72%	WP Workforce Reduction "18.02 and 18.04 DS A&G Split" tab
11	Jurisdictional Allocator	5.30%	5.30%	1 - Jurisdictional Allocator (Company Schedule WPA-5b)
12	Non Jurisdictional Savings	$ 4,086	$ 16,442	Line 9 * Line 10 * Line 11
13	Jurisdictional Compensational Savings for AIU and AMS	$ 283,171	$ 413,222	Line 9 - Line 12
14	**Total Jurisdictional Compensation Savings**	**$ 696,394**		Total of Line 13 for AIU Amount and AMS Amount
15	Pensions and Benefits (Involuntary)	$ 13,081	$ 30,507	Company Exhibit 51.9 workpaper
16	Pensions and Benefits (Voluntary)	49,352	61,653	Company responses to Staff data requests TEE 18.02
17	Total Pensions and Benefits	$ 62,433	$ 92,160	
18	Non-Jurisdictional Pensions & Benefits	$ 888	$ 3,527	Line 17 * Line 10 * Line 11
19	Jurisdictional Pensions & Benefits	$ 61,545	$ 88,633	Line 17 minus line 18
20	**Total Jurisdictional Pensions & Benefits Savings**	**$ 150,178**		Total of Line 19 for AIU Amount and AMS Amount
21	Payroll Tax related to Compensation Savings	$ 21,663	$ 31,612	Line 13 times 7.65%
22	**Total Jurisdictional Payroll Tax**	**$ 53,274**		Total of Line 21 for AIU Amount and AMS Amount
23	Expensed Incentive Compensation per Staff	$ 526		Staff Ex. 15.0, Schedule 15.07, page 2, line 9, col. (g)
24	Expensed Incentive Compensation per Company Direct	2,813		Company Exhibit 51.9 workpaper
25	Percent of Total IC in Revenue Requirement	19%		Line 23 / Line 24

AmerenCIPS Electric
Adjustment to Materials & Supplies
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
1	Accounts Payable Percentage related to Materials & Supplies	10.53%	ICC Staff Exhibit B
2	Materials & Supplies per Company	11,155	Ameren Exhibit 29.2, Schedule 2, Page 1, Line 10, Col. (d)
3	Accounts Payable related to Materials & Supplies	1,175	Line 1 x Line 2
4	Materials & Supplies Net of Related Accounts Payable	9,980	Line 2 - Line 3
5	Materials & Supplies Inventory per Company	11,155	Ameren Exhibit 29.2, Schedule 2, Page 1, Line 10, Col. (d)
6	**Staff Adjustment**	**$ (1,175)**	Line 4 - line 5

AmerenCIPS - Gas

Statement of Operating Income with Adjustments

For the Test Year Ending 12/31/2008

(In Thousands)

Line No.	Description	Company Rebuttal Present (Ex. 30.2, Sch.1)	Staff Adjustments (Appendix D Page 3)	Staff Pro Forma Present (Cols. b+c)	Company Rebuttal Proposed Increase (Ex. 30.2, Sch.1)	Staff Gross Revenue Conversion Factor	Proposed Rates With Staff Adjustments (Cols. d+e+f)	Adjustment To Proposed Increase	Staff Pro Forma Proposed (Cols. g+h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas Service Revenues	$ 70,417	$ -	$ 70,417	$ 7,096	$ -	$ 77,513	$ (6,889)	$ 70,624
2	Other Revenues	2,758	-	2,758	-	-	2,758	-	2,758
3	Total Operating Revenue	73,175	-	73,175	7,096	-	80,271	(6,889)	73,382
4	Uncollectible Accounts	918	-	918	89	-	1,007	(86)	921
5	Production Expenses	1,093	-	1,093	-	-	1,093	-	1,093
6	Storage,Term., and Proc. Expenses	1,867	-	1,867	-	-	1,867	-	1,867
7	Transmission Expenses	725	-	725	-	-	725	-	725
8	Distribution Expenses	18,272	(51)	18,221	-	-	18,221	-	18,221
9	Cust. Accounts,Service & Sales	5,486	(1)	5,485	-	-	5,485	-	5,485
10	Admin. & General Expenses	15,378	(2,954)	12,424	-	-	12,424	-	12,424
11	Depreciation & Amort. Expense	8,396	(59)	8,337	-	-	8,337	-	8,337
12	Taxes Other Than Income	3,165	(111)	3,054	-	-	3,054	-	3,054
13			-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	55,300	(3,176)	52,124	89	-	52,213	(86)	52,127
							-		-
17	State Income Tax	864	265	1,129	512	-	1,641	(497)	1,144
18	Federal Income Tax	3,844	1,173	5,017	2,273	-	7,290	(2,207)	5,083
19		-	-	-	-	-	-	-	-
20	Total Operating Expenses	60,008	(1,738)	58,270	2,874	-	61,144	(2,790)	58,354
21	NET OPERATING INCOME	$ 13,167	$ 1,738	$ 14,905	$ 4,222	$ -	$ 19,127	$ (4,099)	$ 15,028
22	Staff Rate Base (Appendix D, Page 4, Column (d))								$ 195,421
23	Staff Overall Rate of Return (ICC Staff Exhibit 19.0R, Schedule 19.01 CIPS)								7.69%
24	Revenue Change (Col. (i) Line 3 minus Col. (d), Line 3)								$ 207
25	Percentage Revenue Change (Col. (i), Line 24 divided by Col. (d), Line 3)								0.28%

AmerenCIPS - Gas
Adjustments to Operating Income
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Interest Synchronization (Appendix D Page 6)	Incentive compensation (St. Ex. 15.0 Sch 15.07 CIPS-G)	Employee Benefits (St. Ex. 15.0 Sch 15.09 CIPS-G)	Workforce Reduction (Appendix D Page 12)	Pro Forma Plant Additions (St. Ex. 16.0 Sch 16.01 CIPS-G Corrected)	Transportation Fuel Costs (St. Ex. 17.0 Sch 17.01 CIPS-G)	(Source)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas Service Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-			-	-
5	Production Expenses	-	-	-	-	-	-	-	-
6	Storage,Term., and Proc. Expenses	-	-	-	-	-	-	-	-
7	Transmission Expenses	-	-	-	-	-	-	-	-
8	Distribution Expenses	-	-	-	-	-	(51)		(51)
9	Cust. Accounts,Service & Sales	-	-	-	-	-	-		-
10	Admin. & General Expenses	-	(826)	(1,562)	(467)				(2,855)
11	Depreciation & Amort. Expense	-	(8)	-	-	(51)	-		(59)
12	Taxes Other Than Income	-	(81)	-	(29)	-	-	-	(111)
13	-	-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	-	(916)	(1,562)	(496)	(51)	(51)	-	(3,076)
								-	
17	State Income Tax	32	67	114	36	4	4	-	257
18	Federal Income Tax	142	297	507	161	17	17	-	1,141
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	174	(552)	(941)	(299)	(30)	(30)	-	(1,678)
21	NET OPERATING INCOME	$ (174)	$ 552	$ 941	$ 299	$ 30	$ 30	$ -	$ 1,678

AmerenCIPS - Gas
Adjustments to Operating Income
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	(Source)	Industry Association Dues (St. Ex. 18.0R Sch 18.03 CIPS-G)	Customer Service & Info. Expense (St. Ex. 18.0R Sch 18.04 CIPS-G)	Demonstrating & Selling Exp. (St. Ex. 18.0R Sch 18.06 CIPS-G)	(Source)	(Source)	Total Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas Service Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Production Expenses	-	-	-	-	-	-	-	-
6	Storage,Term., and Proc. Expenses	-	-		-	-	-	-	-
7	Transmission Expenses	-	-	-	-	-	-	-	-
8	Distribution Expenses	(51)	-	-	-	-	-	-	(51)
9	Cust. Accounts,Service & Sales	-	-	-	(1)	-	-	-	(1)
10	Admin. & General Expenses	(2,855)		(76)	-	(23)	-		(2,954)
11	Depreciation & Amort. Expense	(59)	-	-	-			-	(59)
12	Taxes Other Than Income	(111)	-	-	-	-	-	-	(111)
13	-	-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	(3,076)	-	(76)	(1)	(23)	-	-	(3,176)
17	State Income Tax	257	-	6	-	2	-	-	265
18	Federal Income Tax	1,141	-	25	-	7	-	-	1,173
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	(1,678)	-	(45)	(1)	(14)	-	-	(1,738)
21	NET OPERATING INCOME	$ 1,678	$ -	$ 45	$ 1	$ 14	$ -	$ -	$ 1,738

AmerenCIPS - Gas
Rate Base
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Company Rebuttal Rate Base (Ex. 30.2, Sch.2)	Staff Adjustments (Appendix D Page 5)	Staff Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Plant in Service	$ 408,595	$ (1,556)	$ 407,039
2	Accumulated Depreciation	(197,390)	8	(197,382)
3	-	-	-	-
4	Net Plant	211,205	(1,548)	209,657
5	Additions to Rate Base			
6	Cash Working Capital	4,345	(1,879)	2,466
7	Materials & Supplies Inventory	33,768	(5,727)	28,041
8	-	-	-	-
9	-	-	-	-
10	-	-	-	-
11	-	-	-	-
12	-	-	-	-
13	-	-	-	-
14	-	-	-	-
15	-	-	-	-
16	Deductions From Rate Base			
17	Customer Advances	(1,115)	-	(1,115)
18	Accumulated Deferred Income Taxes	(40,239)	106	(40,133)
19	Customer Deposits	(1,809)	-	(1,809)
20	Accrued OPEB Liability	-	(1,686)	(1,686)
21	-	-	-	-
22	-	-	-	-
23	Rate Base	$ 206,155	$ (10,734)	$ 195,421

AmerenCIPS - Gas
Adjustments to Rate Base
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Incentive compensation (St. Ex. 15.0 Sch 15.07 CIPS-G)	Cash Working Capital (Appendix D Page 8)	Pro Forma Plant Additions (St. Ex. 16.0 Sch 16.01 CIPS-G Corrected)	Materials & Supplies (Appendix D Page 14)	Accrued OPEB Liabilities (AG/CUB Exhibit 2.1)	(Source)	(Source)	Total Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Plant in Service	$ (239)	$ -	$ (1,317)		$ -		$ -	$ (1,556)
2	Accumulated Depreciation	(8)	-	16		-		-	8
3	-	-	-	-	-	-	-	-	-
4	Net Plant	(247)	-	(1,301)	-	-	-	-	(1,548)
	-								
5	Additions to Rate Base								-
6	Cash Working Capital	-	(1,879)	-	-		-	-	(1,879)
7	Materials & Supplies Inventory	-		-	(5,727)	-	-	-	(5,727)
8		-	-	-	-	-	-	-	-
9		-	-	-	-	-	-	-	-
10		-	-	-	-	-	-	-	-
11		-	-	-	-	-	-	-	-
12		-	-	-	-	-	-	-	-
13		-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15		-	-	-	-	-	-	-	-
16	Deductions From Rate Base	-	-	-	-	-	-	-	-
17	Customer Advances	-	-	-	-	-	-	-	-
18	Accumulated Deferred Income Taxes	5	-	101	-	-	-	-	106
19	Customer Deposits	-	-	-	-	-	-	-	-
20	Accrued OPEB Liability	-	-	-	-	(1,686)	-	-	(1,686)
21		-	-	-	-	-	-	-	-
22		-	-	-	-	-	-	-	-
23	Rate Base	$ (242)	$ (1,879)	$ (1,200)	$ (5,727)	$ (1,686)	$ -	$ -	$ (10,734)

AmerenCIPS - Gas
Interest Synchronization Adjustment
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Amount	
	(a)	(b)	
1	Gross Plant in Service	$ 195,421	(1)
2	Weighted Cost of Debt	2.86%	(2)
3	Synchronized Interest Per Staff	5,589	
4	Company Interest Expense	6,028	(3)
5	Increase (Decrease) in Interest Expense	(439)	
6	Increase (Decrease) in State Income Tax Expense		
7	at 7.300%	$ 32	
8	Increase (Decrease) in Federal Income Tax Expense		
9	at 35.000%	$ 142	

(1) Source: Appendix D, Page 4, Column d.
(2) Source: ICC Staff Exhibit 19.0R, Schedule 19.01 CIPS.
(3) Source: Ameren Schedule 30.2, Schedule 3

AmerenCIPS - Gas
Gross Revenue Conversion Factor
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(a)	(b)	(c)	(d)
1	Revenues		1.000000	
2	Uncollectibles	1.2547%	0.012547	
3	State Taxable Income		0.987453	1.000000
4	State Income Tax	7.3000%	0.072084	0.073000
5	Federal Taxable Income		0.915369	0.927000
6	Federal Income Tax	35.0000%	0.320379	0.324450
7	Operating Income		0.594990	0.602550
8	Gross Revenue Conversion Factor Per Staff		1.680701	1.659613

Ameren/CIPS Gas
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Description (a)		Amount (b)	Source (c)
1	Cash Working Capital per Staff	$	2,466	Appendix D, Page 9, Column e, Line 23
2	Cash Working Capital per Company		4,345	Ameren Ex. 30.2, Schedule 2, page 3, column (G), line 30
3	Difference -- Staff Adjustment	$	(1,879)	Line 1 less Line 2

Ameren/CIPS Gas
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Item (a)	Amount (b)	Lag (Lead) (c)	CWC Factor (d) (c/365)	CWC Requirement (e) (b*d)	Column C Source (f)
1	Revenues	$ 234,644	46.530	0.12748	$ 29,912	Appendix D, Page 10, Column b, Line 6
2	Pass-through Taxes	10,573	0.000	0.00000	-	Line 11 + Line 13 + Line 14 + Line 16 below
3	Total Receipts	$ 245,217				Line 1 + Line 2
4	Employee Benefits	$ 3,330	(17.570)	(0.04814)	(160)	Appendix D, Page 11, Column b, Line 15
5	Payroll	17,322	(12.920)	(0.03540)	(613)	Appendix D, Page 11, Column b, Line 5
6	PGA Purchases	179,959	(39.420)	(0.10800)	(19,436)	Company Schedule B-8, Column F, Line 3
7	Other Operations and Maintenance	19,163	(51.070)	(0.13992)	(2,681)	Appendix D, Page 10, Column b, Line 16
8	FICA	707	(14.740)	(0.04038)	(29)	Appendix D, Page 11, Column b, Line 11
9	Federal Unemployment Tax	9	(76.380)	(0.20926)	(2)	Company Schedule C-18, Column G, Line 3
10	State Unemployment Tax	67	(76.380)	(0.20926)	(14)	Company Schedule C-18, Column G, Line 7
11	ICC Gas Revenue Tax	195	27.470	0.07526	15	Company Schedule C-18, Column E, Line 10
12	Invested Capital Tax	1,117	(30.130)	(0.08255)	(92)	Company Schedule C-18, Column G, Line 12
13	Municipal Utility Tax	3,647	(45.630)	(0.12501)	(456)	Company Schedule C-18, Column E, Line 16
14	Energy Assistance Tax	1,835	(42.280)	(0.11584)	(213)	Company Schedule C-18, Column E, Line 11
15	Corporation Franchise Tax	42	(191.530)	(0.52474)	(22)	Company Schedule C-18, Column G, Line 8
16	Illinois Gas Use and Gas Revenue Tax	4,896	(29.420)	(0.08060)	(395)	Company Schedule C-18, Column E, Line 6
17	Property/Real Estate Tax	1,351	(392.700)	(1.07589)	(1,454)	Company Schedule C-18, Column G, Line 9 + Line 15
18	Interest Expense	5,296	(91.250)	(0.25000)	(1,324)	Appendix D, Page 6, Line 3 - line 19
19	Bank Facility Fees	293	97.650	0.26753	78	Appendix D, Page 4, Column d, line 23 times Bank Facility Fees Weighted Component Sched. 19.01
20	Federal Income Tax	5,083	(38.000)	(0.10411)	(529)	Appendix D, Page 1, Column i, Line 18
21	State Income Tax	1,144	(38.000)	(0.10411)	(119)	Appendix D, Page 1, Column i, Line 17
22	Total Outlays	$ 245,456				Sum of Lines 4 through 21
23	Cash Working Capital per Staff				$ 2,466	Sum of Lines 1 through 22

Ameren/CIPS Gas
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Description (a)	Amount (b)	Source (c)
1	Total Operating Revenues	$ 73,382	Appendix D, Page 1, Column i, Line 3
2	PGA Purchases	179,959	Company Schedule B-8, Column F, Line 3
3	Uncollectible Accounts	(921)	Appendix D, Page 1, Column i, Line 4
4	Depreciation & Amortization	(8,337)	Appendix D, Page 1, Column i, Line 11
5	Return on Equity	(9,439)	Line 9 below
6	Total Revenues for CWC calculation	$ 234,644	Sum of Lines 1 through 5
7	Total Rate Base	$ 195,421	Appendix D, Page 4, Column d, Line 23
8	Weighted Cost of Capital	4.83%	ICC Staff Ex. 19.0, Schedule 19.01 CIPS
9	Return on Equity	$ 9,439	Line 7 times Line 8
10	Operating Expense Before Income Taxes	$ 52,127	Appendix D, Page 1, Column i, Line 16
11	Employee Benefits Expense	(3,330)	Appendix D, Page 11, Column b, Line 15
12	Payroll Expense	(17,322)	Appendix D, Page 11, Column b, Line 5
13	Uncollectible Accounts	(921)	Appendix D, Page 1, Column i, Line 4
14	Depreciation & Amortization	(8,337)	Appendix D, Page 1, Column i, Line 11
15	Taxes Other Than Income	(3,054)	Appendix D, Page 1, Column i, Line 12
16	Other Operations & Maintenance for CWC Calculation	$ 19,163	Sum of Lines 10 through 15

Ameren/CIPS Gas
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Description (a)	Amount (b)	Source (c)
1	Direct Payroll per Company Filing	$ 19,113	Company Schedule B-8, Column F, Line 2
2	Staff Labor Adjustment	(585)	ICC Staff Ex. 1.0, Sch. 1.09 CIPS-G, Line 3
3	Adjustment for Workforce Reduction	(380)	Appendix D, Page 12, Line 3
4	Adjustment for Incentive Compensation	(826)	ICC Staff Ex. 15.0, Sch. 15.07 CIPS-G, Page 1, Line 6
5	Direct Payroll per Staff	$ 17,322	Sum of Lines 1 through 4
6	FICA Tax per Company Filing	$ 859	Company Schedule C-18, Column G, Line 2
7	Labor Adjustment	(45)	ICC Staff Ex. 1.0, Sch. 1.09 CIPS-G, Line 5
8	Incentive Compensation Adjustment	(81)	ICC Staff Ex. 15.0, Sch. 15.07 CIPS-G, Page 1, Line 20
9	Adjustment for Workforce Reduction	(29)	Appendix D, Page 12, Line 7
10	Company FICA Correction Adjustment	4	ICC Staff Ex. 1.0, Sch. 1.11 CIPS-G, Line 13
11	FICA Tax per Staff	$ 707	Sum of Lines 6 through 10
12	Employee Benefits per Company Filing	$ 4,979	Company Schedule B-8, Column F, Line 1
13	Adjustment for Workforce Reduction	(87)	Appendix D, Page 12, Line 6
14	Staff Adjustment	(1,562)	ICC Staff Ex. 15.0, Sch. 15.09 CIPS-G, Line 9
15	Employee Benefits per Staff	$ 3,330	Sum of Lines 12 through 14

AmerenCIPS - Gas
Adjustment for Workforce Reduction
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Amount		Source
	(a)	(b)		(d)
1	Staff Proposed Compensation Savings	$	(380)	Appendix D, Page 13, line 10
2	Company CompensationSavings Rebuttal		-	
3	**Staff Proposed Adjustment**	$	(380)	
4	Staff Pension & Benefits Proposed Savings	$	(87)	Appendix D, Page 13, line 15
5	Company Pension & Benefits Savings Rebuttal		-	
6	**Staff Proposed Adjustment**	$	(87)	
7	**Taxes Other Than Income Adjustment**	$	(29)	Appendix D, Page 13, line 11

AmerenCIPS - Gas
Adjustment for Workforce Reduction
For the Test Year Ending 12/31/2008
(In Dollars)

Line No.	Description	AIU Amount	AMS Amount	Source
	(a)	(b)	(c)	(d)
1	Salaries (Involuntary)	$ 25,122	$ 58,498	Company Exhibit 51.9 workpaper
2	Salaries (Voluntary)	94,779	192,617	Company responses to Staff data requests TEE 18.02
3	Total Salaries	$ 119,901	$ 251,115	
4	Incentive Compensation (Involuntary)	$ 2,010	$ 6,935	Company Exhibit 51.9 workpaper
5	Incentive Compensation (Voluntary)	6,720	33,856	Company responses to Staff data requests TEE 18.02
6	Total Incentive Compensation	$ 8,730	$ 40,791	
7	Percent of Total IC in Revenue Requirement	19%	19%	Line 18
8	Total Incentive Compensation	$ 1,633	$ 7,630	Line 9 * Line 10
9	Jurisdictional Compensation Savings for AIU and AMS	$ 121,534	$ 258,745	Sum of Lines 3, 8
10	**Total Jurisdictional Compensation Savings**	**$ 380,279**		Total of Line 9 for AIU Amount and AMS Amount
11	**Payroll related to Net Savings**	**$ 29,091**		Line 10 times 7.65%
12	Pensions and Benefits (Involuntary)	$ 5,914	$ 13,770	Company Exhibit 51.9 workpaper
13	Pensions and Benefits (Voluntary)	22,311	45,342	Company responses to Staff data requests TEE 18.02
14	Total Pensions and Benefits	$ 28,225	$ 59,112	
15	**Total Jurisdictional Pension & Benefits Savings**	**$ 87,337**		
16	Expensed Incentive Compensation per Staff	$ 257		Staff Ex. 15.0, Schedule 15.07, page 2, line 9, col. (g)
17	Expensed Incentive Compensation per Company Direct	$ 1,374		Company Exhibit 51.9 workpaper
18	Percent of Total IC in Revenue Requirement	19%		Line 16 / Line 17

AmerenCIPS Gas
Adjustment to Materials & Supplies (Including Gas in Storage)
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
1	Materials & Supplies (Including Gas in Storage) per Staff	$ 28,041	Appendix D, Page 14, Line 9, Col. (b)
2	Materials & Supplies (Including Gas in Storage) per Company	33,768	Ameren Exhibit 30.2, Schedule 2, page 1, Line 7, Col. (d)
3	**Staff Adjustment**	**$ (5,727)**	Line 1 - line 2

AmerenCIPS Gas
Adjustment to Materials & Supplies (Including Gas in Storage)
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
	General Materials and Supplies		
1	Accounts Payable Percentage related to Materials & Supplies	10.53%	ICC Staff Exhibit B
2	General materials & Supplies per Company	1,747	Ameren Exhibit 30.8 CIP G, Page 2, Line 1, Col. (b)
3	Accounts Payable related to Materials & Supplies	184	Line 1 x Line 2
4	General Materials & Supplies Net of Related Accounts Payable	**1,563**	Line 2 - Line 3
	Gas in Storage		
5	Accounts Payable Percentage related to Gas in Storage	6.63%	ICC Staff Exhibit B
6	13-Month Average of Gas in Storage per Staff	28,358	Appendix D, Page 15, Column (b), Line 3
7	Accounts Payable related to Gas in Storage	1,880	Line 1 x Line 2
8	Gas in Storage Net of Related Accounts Payable	**26,478**	Line 6 - Line 7
9	Total Materials & Supplies (Including Gas in Storage) per Staff	**28,041**	Line 4 + Line 8

AmerenCIPS Gas
Adjustment to Materials & Supplies (Including Gas in Storage)
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
1	13-month Average Balance Gas in Storage per Company	$ 32,021	Ameren Exhibit 30.8 CIP G, Page 2, Line 2, Col. (b)
2	Adjustment to 13-month Average Balance Gas in Storage	(3,663)	ICC Staff Exhibit 25.0, Schedule 25.02 CIPS-G
3	13-month Average Balance Gas in Storage per Staff	**$ 28,358**	Line 1 + line 2

AmerenIP - Electric

Statement of Operating Income with Adjustments

For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Company Rebuttal Present (Ex. 29.3, Sch.1)	Staff Adjustments (Appendix E Page 4)	Staff Pro Forma Present (Cols. b+c)	Company Rebuttal Proposed Increase (Ex. 29.3, Sch.1)	Staff Gross Revenue Conversion Factor	Proposed Rates With Staff Adjustments (Cols. d+e+f)	Adjustment To Proposed Increase	Staff Pro Forma Proposed (Cols. g+h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Electric Operating Revenues	$ 443,459	$ -	$ 443,459	$ 72,823	$ -	$ 516,282	$ (41,885)	$ 474,397
2	Other Revenues	18,493	-	18,493	-	-	18,493	-	18,493
3	Total Operating Revenue	461,952	-	461,952	72,823	-	534,775	(41,885)	492,890
4	Uncollectible Accounts	4,787	-	4,787	755	-	5,542	(434)	5,108
5	Distribution Expenses	106,015	(3,441)	102,574	-	-	102,574	-	102,574
6	Customer Accounts Expense	23,966	(129)	23,837	-	-	23,837	-	23,837
7	Admin. & General Expenses	85,549	(6,993)	78,556	-	-	78,556	-	78,556
8	Depreciation & Amort. Expenses	86,823	(8,441)	78,382	-	-	78,382	-	78,382
9	Taxes Other Than Income	30,804	(3,412)	27,392	-	-	27,392	-	27,392
10			-	-	-	-	-	-	-
11			-	-	-	-	-	-	-
12			-	-	-	-	-	-	-
13			-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	337,944	(22,416)	315,528	755	-	316,283	(434)	315,849
							-		-
17	State Income Tax	4,169	1,811	5,980	5,261	-	11,241	(3,026)	8,215
18	Federal Income Tax	18,538	8,054	26,592	23,382	1	49,975	(13,449)	36,526
19		-	-	-	-	-	-	-	-
20	Total Operating Expenses	360,651	(12,551)	348,100	29,398	1	377,499	(16,909)	360,590
21	NET OPERATING INCOME	$ 101,301	$ 12,551	$ 113,852	$ 43,425	$ (1)	$ 157,276	$ (24,976)	$ 132,300
22	Staff Rate Base (Appendix E, Page 5, Column (d))								$ 1,461,873
23	Staff Overall Rate of Return (ICC Staff Exhibit 19.0R, Schedule 19.01 IP)								9.05%
24	Revenue Change (Col. (i) Line 3 minus Col. (d), Line 3)								$ 30,938
25	Percentage Revenue Change (Col. (i), Line 24 divided by Col. (d), Line 3)								6.70%

AmerenIP - Electric
Adjustments to Operating Income
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Interest Synchronization (Appendix E page 7)	Incentive Compensation (St. Ex. 15.0 Sch 15.07 IP-E)	Employee Benefits (St. Ex. 15.0 Sch 15.09 IP-E)	Workforce Reduction (Appendix E page 13)	Production Retiree Expense (St. Ex. 15.0 Sch 15.11 IP-E)	Electric Distribution Tax (St. Ex. 15.0 Sch 15.12 IP-E)	(Source)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-			-	-
5	Distribution Expenses	-	-	-	-	-	-	-	-
6	Customer Accounts Expense	-	-	-	-	-	-	-	-
7	Admin. & General Expenses	-	(2,146)	(4,256)	(515)	393			(6,524)
8	Depreciation & Amort. Expenses	-	(22)	-		-	-	-	(22)
9	Taxes Other Than Income	-	(214)	-	(30)		(3,168)		(3,412)
10		-	-	-	-	-	-	-	-
11		-	-	-	-	-	-	-	-
12		-	-	-	-	-	-	-	-
13		-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	-	(2,383)	(4,256)	(545)	393	(3,168)	-	(9,958)
								-	
17	State Income Tax	175	174	311	40	(29)	231	-	902
18	Federal Income Tax	780	773	1,381	177	(128)	1,028	-	4,011
19		-	-	-	-	-	-	-	-
20	Total Operating Expenses	955	(1,436)	(2,564)	(328)	236	(1,909)	-	(5,045)
21	NET OPERATING INCOME	$ (955)	$ 1,436	$ 2,564	$ 328	$ (236)	$ 1,909	$ -	$ 5,045

AmerenIP - Electric
Adjustments to Operating Income
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Pro Forma Plant Additions (St. Ex. 16.0 Sch 16.01 IP-E Corrected)	Regul. Asset Amortization (Appendix E page 15)	NESC Adjustment (St. Ex. 16.0 Sch 16.03 IP-E)	Transportation Fuel Costs (St. Ex. 17.0 Sch 17.01 IP-E)	Tree Trimming (St. Ex. 17.0 Sch 17.02 IP-E)	Lobbying Expense (St. Ex. 18.0R Sch 18.01 IP-E)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Distribution Expenses	-	-	-	(1,195)	(560)	(1,686)	-	(3,441)
6	Customer Accounts Expense	-		-	-	-	-	-	-
7	Admin. & General Expenses	(6,524)	-	-	-		-	(15)	(6,539)
8	Depreciation & Amort. Expenses	(22)	(467)	(7,899)	(22)	-	-	-	(8,411)
9	Taxes Other Than Income	(3,412)	-	-	-	-	-	-	(3,412)
10		-	-	-	-	-	-	-	-
11		-	-	-	-	-	-	-	-
12		-	-	-	-	-	-	-	-
13		-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	(9,958)	(467)	(7,899)	(1,217)	(560)	(1,686)	(15)	(21,803)
17	State Income Tax	902	34	577	89	41	123	1	1,767
18	Federal Income Tax	4,011	152	2,563	395	182	547	5	7,855
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	(5,045)	(281)	(4,759)	(733)	(337)	(1,016)	(9)	(12,181)
21	NET OPERATING INCOME	$ 5,045	$ 281	$ 4,759	$ 733	$ 337	$ 1,016	$ 9	$ 12,181

AmerenIP - Electric
Adjustments to Operating Income
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Remove Transmission Operations Plant (St. Ex. 18.0R Sch 18.02 IP-E)	Industry Association Dues (St. Ex. 18.0R Sch 18.03 IP-E)	Customer Service & Info. Expense (St. Ex. 18.0R Sch 18.04 IP-E)	Demonstrating & Selling (St. Ex. 18.0R Sch 18.06 IP-E)	(Source)	(Source)	Total Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Distribution Expenses	(3,441)			-	-	-	-	(3,441)
6	Customer Accounts Expense	-	-	-	(129)	-	-	-	(129)
7	Admin. & General Expenses	(6,539)	-	(148)	-	(306)	-		(6,993)
8	Depreciation & Amort. Expenses	(8,411)	(30)	-	-	-	-	-	(8,441)
9	Taxes Other Than Income	(3,412)	-	-	-	-	-	-	(3,412)
10		-	-	-	-	-	-	-	-
11		-	-	-	-	-	-	-	-
12		-	-	-	-	-	-	-	-
13		-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	(21,803)	(30)	(148)	(129)	(306)	-	-	(22,416)
17	State Income Tax	1,767	2	11	9	22	-	-	1,811
18	Federal Income Tax	7,855	10	48	42	99	-	-	8,054
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	(12,181)	(18)	(89)	(78)	(185)	-	-	(12,551)
21	NET OPERATING INCOME	$ 12,181	$ 18	$ 89	$ 78	$ 185	$ -	$ -	$ 12,551

AmerenIP - Electric
Rate Base
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Company Rebuttal Rate Base (Ex. 29.3, Sch.2)	Staff Adjustments (Appendix E page 6)	Staff Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Plant in Service	$ 2,410,254	$ (17,565)	$ 2,392,689
2	Accumulated Depreciation	(743,911)	(1,467)	(745,378)
3	-	-	-	-
4	Net Plant	1,666,343	(19,032)	1,647,311
5	Additions to Rate Base			
6	Cash Working Capital	523	(1,638)	(1,115)
7	Materials & Supplies Inventory	17,782	(1,873)	15,909
8	CWIP Not Subject to AFUDC	16	-	16
9		-	-	-
10		-	-	-
11		-	-	-
12		-	-	-
13		-	-	-
14		-	-	-
15		-	-	-
16	Deductions From Rate Base			
17	Customer Advances	(17,579)	-	(17,579)
18	Accumulated Deferred Income Taxes	(158,910)	701	(158,209)
19	Customer Deposits	(9,489)	-	(9,489)
20	Accrued OPEB, net of ADIT	(12,959)	(2,012)	(14,971)
21	-	-	-	-
22	-	-	-	-
23	Rate Base	$ 1,485,727	$ (23,854)	$ 1,461,873

AmerenIP - Electric
Adjustments to Rate Base
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Incentive Compensation (St. Ex. 15.0 Sch 15.07 IP-E)	Cash Working Capital (Appendix E page 9)	Pro Forma Plant Additions (St. Ex. 16.0 Sch 16.01 IP-E Corrected)	NESC Adjustment (St. Ex. 16.0 Sch 16.03 IP-E)	Remove Transmission Operations Plant (St. Ex. 18.0 Sch 18.02 IP-E)	Materials & Supplies (Appendix E page 17)	Accrued OPEB Liabilities (St. Ex. 15.0 Sch 15.14 IP-E)	Total Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Plant in Service	$ (657)	$ -	$ (15,238)	$ (693)	$ (977)	$ -	$ -	$ (17,565)
2	Accumulated Depreciation	(22)	-	(1,766)	21	300	-	-	(1,467)
3	-	-	-	-	-	-	-	-	-
4	Net Plant	(679)	-	(17,004)	(672)	(677)	-	-	(19,032)
	-								
5	Additions to Rate Base								-
6	Cash Working Capital	-	(1,638)	-	-	-	-		(1,638)
7	Materials & Supplies Inventory	-		-	-	-	(1,873)	-	(1,873)
8	CWIP Not Subject to AFUDC	-	-	-	-		-	-	-
9		-	-	-	-	-	-	-	-
10		-	-	-	-	-	-	-	-
11		-	-	-	-	-	-	-	-
12		-	-	-	-	-	-	-	-
13		-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15		-	-	-	-	-	-	-	-
16	Deductions From Rate Base	-	-	-	-	-	-	-	-
17	Customer Advances	-	-	-	-	-	-	-	-
18	Accumulated Deferred Income Taxes	13	-	472	150	66	-	-	701
19	Customer Deposits	-	-	-	-	-	-	-	-
20	Accrued OPEB, net of ADIT	-	-	-	-	-	-	(2,012)	(2,012)
21		-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-
	-								
23	Rate Base	$ (666)	$ (1,638)	$ (16,532)	$ (522)	$ (611)	$ (1,873)	$ (2,012)	$ (23,854)

AmerenIP - Electric
Interest Synchronization Adjustment
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Amount	
	(a)	(b)	
1	Gross Plant in Service	$ 1,461,873	(1)
2	Weighted Cost of Debt	4.41%	(2)
3	Synchronized Interest Per Staff	64,469	
4	Company Interest Expense	66,873	(3)
5	Increase (Decrease) in Interest Expense	(2,404)	
6	Increase (Decrease) in State Income Tax Expense		
7	at 7.300%	$ 175	
8	Increase (Decrease) in Federal Income Tax Expense		
9	at 35.000%	$ 780	

(1) Appendix E, Page 5, Column (d), Line 23.
(2) Source: ICC Staff Exhibit 19.0R, Schedule 19.01 IP.
(3) Source: Ameren Exhibit 29.3, Schedule 3.

AmerenIP - Electric
Gross Revenue Conversion Factor
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(a)	(b)	(c)	(d)
1	Revenues		1.000000	
2	Uncollectibles	1.0362%	0.010362	
3	State Taxable Income		0.989638	1.000000
4	State Income Tax	7.3000%	0.072244	0.073000
5	Federal Taxable Income		0.917394	0.927000
6	Federal Income Tax	35.0000%	0.321088	0.324450
7	Operating Income		0.596306	0.602550
8	Gross Revenue Conversion Factor Per Staff		1.676991	1.659613

Ameren/IP Electric
Adjustment to Cash Working Capital
For the Test Year Ending December 31, 2008
(In Thousands)

Line	Description (a)	Amount (b)	Source (c)
1	Cash Working Capital per Staff	$ (1,115)	Appendix E, Page 10, Column e, Line 22
2	Cash Working Capital per Company	523	Ameren Exhibit 29.3, Schedule 2, page 4, column (G), line 24
3	Difference -- Staff Adjustment	$ (1,638)	Line 1minus Line 2

Ameren/IP Electric
Adjustment to Cash Working Capital
For the Test Year Ending December 31, 2008
(In Thousands)

Line	Item (a)	Amount (b)	Lag (Lead) (c)	CWC Factor (d) (c/365)	CWC Requirement (e) (b*d)	Column C Source (f)
1	Revenues	$ 341,569	46.550	0.12753	$ 43,562	Appendix E, Page 11, Column b, Line 7
2	Pass-through Taxes	6,965	0.000	0.00000	-	Line 12 + Line 13 below
3	Total Receipts	$ 348,534				Line 1 + Line 2
4	Employee Benefits	$ 21,329	(17.570)	(0.04814)	(1,027)	Appendix E, Page 12, Column b, Line 16
5	Payroll	61,882	(12.920)	(0.03540)	(2,190)	Appendix E, Page 12, Column b, Line 5
6	Purchased Power	-	0.000	0.00000	-	
7	Other Operations and Maintenance	121,756	(51.070)	(0.13992)	(17,036)	Appendix E, Page 11, Column b, Line 17
8	FICA	3,046	(14.740)	(0.04038)	(123)	Appendix E, Page 12, Column b, Line 11
9	Federal Unemployment Tax	21	(76.380)	(0.20926)	(4)	Company Schedule C-18, Column J, Line 3
10	State Unemployment Tax	30	(76.380)	(0.20926)	(6)	Company Schedule C-18, Column J, Line 7
11	Electricity Distribution Tax	21,889	(30.130)	(0.08255)	(1,807)	ICC Staff Ex. 15.0, Sch. 15.12 IP-E, Column b, Line 1
12	Federal Excise Tax	1	(45.630)	(0.12501)	-	Company Schedule C-18, Column J, Line 4
13	Energy Assistance Tax	6,964	(42.280)	(0.11584)	(807)	Company Schedule C-18, Column H, Line 9
14	Corporation Franchise Tax	860	(191.530)	(0.52474)	(451)	Company Schedule C-18, Column J, Line 8
15	Gross Receipts/Municipal Utility Tax	-	(45.630)	(0.12501)	-	Company Schedule C-18, Column J, Line 11
16	Property/Real Estate Tax	1,544	(392.700)	(1.07589)	(1,661)	Company Schedule C-18, Column J, Line 13
17	Interest Expense	62,130	(91.250)	(0.25000)	(15,533)	Appendix E. Page 7, Line 3 - line 18
18	Bank Facility Fees	2,339	97.650	0.26753	626	Appendix E, Page 5, Column d, line 23 times Bank Facility Fees Weighted Component Sched. 19.01
19	Federal Income Tax	36,526	(38.000)	(0.10411)	(3,803)	Appendix E, Page 1, Column i, Line 18
20	State Income Tax	8,215	(38.000)	(0.10411)	(855)	Appendix E, Page 1, Column i, Line 17
21	Total Outlays	$ 348,532				Sum of Lines 4 through 20
22	Cash Working Capital per Staff				$ (1,115)	Sum of Lines 1 through 20

Ameren/IP Electric
Adjustment to Cash Working Capital
For the Test Year Ending December 31, 2008
(In Thousands)

Line	Revenues (a)		Amount (b)	Source (c)
1	Total Operating Revenues	$	492,890	Appendix E, page 1, Column i, Line 3
2	Purchased Power		-	
3	Uncollectible Accounts		(5,108)	Appendix E, Page 1, Column i, Line 4
4	Depreciation & Amortization		(78,382)	Appendix E, page 1, Column i, Line 8
5	Return on Equity		(67,831)	Line 10 below
6			-	
7	Total Revenues for CWC calculation	$	341,569	Sum of Lines 1 through 6
8	Total Rate Base	$	1,461,873	Appendix E, Page 5, Column d, Line 23
9	Weighted Cost of Capital		4.64%	ICC Staff Ex. 19.0R, Schedule 19.01 IP
10	Return on Equity	$	67,831	Line 8 times Line 9
11	Operating Expense Before Income Taxes	$	315,849	Appendix E, Page 1, Column i, Line 16
12	Employee Benefits Expense		(21,329)	Appendix E, Page 12, Column b, Line 16
13	Payroll Expense		(61,882)	Appendix E, Page 12, Column b, Line 5
14	Uncollectible Accounts		(5,108)	Appendix E, Page 1, Column i, Line 4
15	Depreciation & Amortization		(78,382)	Appendix E, page 1, Column i, Line 8
16	Taxes Other Than Income		(27,392)	Appendix E, Page 1, Column i, Line 9
17	Other Operations & Maintenance for CWC Calculation	$	121,756	Sum of Lines 11 through 16

Ameren/IP Electric
Adjustment to Cash Working Capital
For the Test Year Ending December 31, 2008
(In Thousands)

Line	Description (a)	Amount (b)	Source (c)
1	Direct Payroll per Company Filing	$ 66,250	Company Schedule B-8, Column F, Line 2
2	Staff Labor Adjustment	(1,836)	ICC Staff Ex. 1.0, Sch. 1.09 IP-E, Line 3
3	Adjustment for Workforce Reduction	(386)	Appendix E, Page 13, Line 3
4	Adjustment for Incentive Compensation	(2,146)	ICC Staff Ex. 15.0, Sch. 15.07 IP-E, Page 1, Line 6
5	Direct Payroll per Staff	$ 61,882	Sum of Lines 1 through 4
6	FICA Tax per Company Filing	$ 3,442	Company Schedule C-18, Column J, Line 2
7	Labor Adjustment	(140)	ICC Staff Ex. 1.0, Sch. 1.09 IP-E, Line 5
8	Incentive Compensation Adjustment	(214)	ICC Staff Ex. 15.0, Sch. 15.07 IP-E, Page 1, Line 20
9	Adjustment for Workforce Reduction	(30)	Appendix E, Page 13, Line 7
10	Company FICA Correction Adjustment	(12)	ICC Staff Ex. 1.0, Sch. 1.11 IP-E, Line 13
11	FICA Tax per Staff	$ 3,046	Sum of Lines 6 through 10
12	Employee Benefits per Company Filing	$ 25,321	Company Schedule B-8, Column F, Line 1
13	Staff Adjustment for Employee Benefits	(4,256)	ICC Staff Ex. 15.0, Sch. 15.09 IP-E, Line 7
14	Adjustment for Workforce Reduction	(129)	Appendix E, Page 13, Line 6
15	Staff Adjustment for Retiree Benefits	393	ICC Staff Ex. 15.0, Sch. 15.11 IP-E, Line 5
16	Employee Benefits per Staff	$ 21,329	Sum of Lines 12 through 15

AmerenIP - Electric
Adjustment for Workforce Reduction
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(d)
1	Staff Proposed Compensation Savings	$ (386)	Appendix E, Page 14 line 14
2	Company CompensationSavings Rebuttal	-	
3	**Staff Proposed Adjustment**	$ (386)	
4	Staff Pension & Benefits Proposed Savings	$ (129)	Appendix E, Page 14 line 20
5	Company Pension & Benefits Savings Rebuttal	-	
6	**Staff Proposed Adjustment**	$ (129)	
7	**Taxes Other Than Income Adjustment**	$ (30)	Appendix E, Page 14, line 22

AmerenIP - Electric
Adjustment for Workforce Reduction
For the Test Year Ending December 31, 2008
(in Dollars)

Line No.	Description	AIU Amount	AMS Amount	Source
	(a)	(b)	(c)	(d)
1	Salaries (Involuntary)	$ 41,169	$ 178,045	Company Exhibit 51.9 workpaper
2	Salaries (Voluntary)	-	165,391	Company responses to Staff data requests TEE 18.02
3	Total Salaries	$ 41,169	$ 343,436	
4	Incentive Compensation (Involuntary)	$ 3,293	$ 21,107	Company Exhibit 51.9 workpaper
5	Incentive Compensation (Voluntary)	-	33,823	Company responses to Staff data requests TEE 18.02
6	Total Incentive Compensation	$ 3,293	$ 54,930	
7	Percent of Total IC in Revenue Requirement	19%	19%	Line 25
8	Total Incentive Compensation	$ 627	$ 10,459	Line 6 * Line 7
9	Total Compensation Savings	$ 41,796	$ 353,895	Sum of Lines 3, 8
10	Percent A&G Related	27%	72%	WP Workforce Reduction "18.02 and 18.04 DS A&G Split" tab
11	Jurisdictional Allocator	3.75%	3.75%	1 - Jurisdictional Allocator (Company Schedule WPA-5b)
12	Non Jurisdictional Savings	$ 421	$ 9,583	Line 9 * Line 10 * Line 11
13	Jurisdictional Compensational Savings for AIU and AMS	$ 41,375	$ 344,312	Line 9 - Line 12
14	**Total Jurisdictional Compensation Savings**	**$ 385,688**		Total of Line 13 for AIU Amount and AMS Amount
15	Pensions and Benefits (Involuntary)	$ 13,104	$ 56,672	Company Exhibit 51.9 workpaper
16	Pensions and Benefits (Voluntary)	-	62,644	Company responses to Staff data requests TEE 18.02
17	Total Pensions and Benefits	$ 13,104	$ 119,316	
18	Non-Jurisdictional Pensions & Benefits	$ 132	$ 3,231	Line 17 * Line 10 * Line 11
19	Jurisdictional Pensions & Benefits	$ 12,972	$ 116,085	Line 17 minus line 18
20	**Total Jurisdictional Pensions & Benefits Savings**	**$ 129,057**		Total of Line 19 for AIU Amount and AMS Amount
21	Payroll Tax related to Compensation Savings	$ 3,165	$ 26,340	Line 13 times 7.65%
22	**Total Jurisdictional Payroll Tax**	**$ 29,505**		Total of Line 21 for AIU Amount and AMS Amount
23	Expensed Incentive Compensation per Staff	$ 707		Staff Ex. 15.0, Schedule 15.07, page 2, line 9, col. (g)
24	Expensed Incentive Compensation per Company Direct	3,713		Company Exhibit 51.9 workpaper
25	Percent of Total IC in Revenue Requirement	19%		Line 23 / Line 24

AmerenIP
Electric
For the test Year Ended December 31, 2008
Adjustment to Regulatory Asset Amortization
In Thousands

Line No.	Description	Amount	Source
	(a)	(b)	(c)
1	Amortization of Regulatory Asset per Staff	$ 3,950	Appendix E, Page 16, col. (b), line 11
2	Amortization of Regulatory Asset per Company	11,849	Co. WPC 2.25
3	Difference-Staff Adjustment	$ (7,899)	Line 1 - line 2

AmerenIP
Electric
For the test Year Ended December 31, 2008
Adjustment to Regulatory Asset Amortization
In Thousands

Line No.	Description (a)	Amount (b)	Source (c)
1	Annual Amortization	$ 16,750	Docket No. 04-0294
2	Monthly Amortization	1,396	Line 1 / 12
3	Number of months in 2010 Docket No. 09-0306 (Cons.) rates to be in effect	8	May 2010-December 2010
4	Amount to be Amortized in 2010	$ 11,167	Line 2 x line 3
5	Number of Years Docket No. 09-0306 (Cons.) rates expected to be in effect	2	Co. WPC-10
6	Amortization Amount	$ 5,583	Line 4 / line 5
	Allocation by Rate Base		
7	Electric Rate Base-Docket No. 07-0585	$ 1,254	Co. WPC-2.25
8	Gas rate Base- Docket No. 07-0585	519	Co. WPC-2.25
9	Combined Rate Base 07-0585	$ 1,773	Line 7 + Line 8
10	Electric Rate Base Percentage	70.74%	Line 7 / line 9
11	Electric Amortization Amount	$ 3,950	Line 6 x line 10

AmerenIP Electric
Adjustment to Materials & Supplies
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
1	Accounts Payable Percentage related to Materials & Supplies	10.53%	ICC Staff Exhibit B
2	Materials & Supplies per Company	17,783	Ameren Exhibit 29.3, Schedule 2, Page 1, Line 8, Col. (d)
3	Accounts Payable related to Materials & Supplies	1,873	Line 1 x Line 2
4	Materials & Supplies Net of Related Accounts Payable	15,910	Line 2 - Line 3
5	Materials & Supplies Inventory per Company	17,783	Ameren Exhibit 29.3, Schedule 2, Page 1, Line 8, Col. (d)
6	Staff Adjustment	$ (1,873)	Line 1 - line 2

AmerenIP - Gas

Statement of Operating Income with Adjustments

For the Test Year Ending 12/31/2008

(In Thousands)

Line No.	Description	Company Rebuttal Present (Ex. 30.3, Sch.1)	Staff Adjustments (Appendix F page 4)	Staff Pro Forma Present (Cols. b+c)	Company Rebuttal Proposed Increase (Ex. 30.3, Sch.1)	Staff Gross Revenue Conversion Factor	Proposed Rates With Staff Adjustments (Cols. d+e+f)	Adjustment To Proposed Increase	Staff Pro Forma Proposed Before Used & Useful Allowance (Cols. g+h)	Staff Proposed Used & Useful Allowance	Staff Pro Forma Proposed After Used & Useful Allowance (Cols. i+j)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Gas Service Revenues	166,030	-	166,030	13,065	(2)	179,093	(18,775)	160,318	125	$ 160,443
2	Other Revenues	5,161	-	5,161	-	-	5,161	-	5,161	-	5,161
3	Total Operating Revenue	171,191	-	171,191	13,065	(2)	184,254	(18,775)	165,479	125	165,604
4	Uncollectible Accounts	2,878	-	2,878	220	-	3,098	(316)	2,782	2	2,784
5	Production Expenses	1,121	-	1,121	-	-	1,121	-	1,121	-	1,121
6	Storage,Term., and Proc. Expenses	3,596	-	3,596	-	-	3,596	-	3,596	-	3,596
7	Transmission Expenses	2,926	-	2,926	-	-	2,926	-	2,926	-	2,926
8	Distribution Expenses	31,897	(737)	31,160	-	-	31,160	-	31,160	-	31,160
9	Cust. Accounts,Service & Sales	11,642	(1)	11,641	-	-	11,641	-	11,641	-	11,641
10	Admin. & General Expenses	29,143	(3,455)	25,688	-	-	25,688	-	25,688	-	25,688
11	Depreciation & Amort. Expense	25,026	(3,406)	21,620	-	-	21,620	-	21,620	-	21,620
12	Taxes Other Than Income	6,081	(151)	5,930	-	-	5,930	-	5,930	-	5,930
13			-	-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-	-	-
15	Total Operating Expense										
16	Before Income Taxes	114,310	(7,751)	106,559	220	-	106,779	(316)	106,463	2	106,465
							-		-		
17	State Income Tax	2,368	699	3,067	938	-	4,005	(1,348)	2,657	9	2,666
18	Federal Income Tax	10,520	3,095	13,615	4,168	(1)	17,782	(5,989)	11,793	40	11,833
19		-	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	127,198	(3,957)	123,241	5,326	(1)	128,566	(7,653)	120,913	51	120,964
21	NET OPERATING INCOME	43,993	3,957	47,950	7,739	(1)	55,688	(11,122)	44,566	74	$ 44,640
22	Staff Rate Base (Appendix F, Page 5, Column (d))								512,245		
23	Staff Overall Rate of Return (ICC Staff Exhibit 19.0R, Schedule 19.01 IP)								8.70%		
24	Non-used and Useful Investment (ICC Staff Exhibit 15.0, Schedule 15.13, page 1, column (f), line 5.										$ 1,706
25	Staff Rate of Return Excluding Common Equity Return (ICC Staff Exhibit 19.0, Schedule 19.01).										4.34%
26	Revenue Change (Col. (k) Line 3 minus Col. (d), Line 3).										$ (5,587)
27	Percentage Revenue Change excluding PGA Revenues (Col. (k), Line 26 divided by Col. (d), Line 3).										-3.26%

AmerenIP - Gas
Adjustments to Operating Income
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Interest Synchronization (Appendix F page 8)	Incentive Compensation (St. Ex. 15.0 Sch 15.07 IP-G)	Employee Benefits (St. Ex. 15.0 Sch 15.09 IP-G)	Workforce Reduction (Appendix F page 14)	Pro Forma Plant Additions (St. Ex. 16.0 Sch 16.01 IP-G Corrected)	Reg. Asset Amortization (Appendix F page 16)	(Source)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas Service Revenues	-	-	-	-	-	-	-	-
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-				-	-
5	Production Expenses	-	-	-	-	-	-	-	-
6	Storage,Term., and Proc. Expenses	-	-	-	-	-	-	-	-
7	Transmission Expenses	-	-	-	-	-	-	-	-
8	Distribution Expenses	-	-	-	-	-	-	-	-
9	Cust. Accounts,Service & Sales	-	-	-	-	-	-	-	-
10	Admin. & General Expenses	-	(1,225)	(1,817)	(291)	-			(3,333)
11	Depreciation & Amort. Expense	-	(18)	-	-	(106)	(3,267)		(3,391)
12	Taxes Other Than Income	-	(134)	-	(17)	-	-	-	(151)
13	-	-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	-	(1,377)	(1,817)	(308)	(106)	(3,267)	-	(6,876)
								-	
17	State Income Tax	131	101	133	23	8	239	-	635
18	Federal Income Tax	581	447	590	100	34	1,060	-	2,812
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	712	(829)	(1,094)	(185)	(64)	(1,968)	-	(3,429)
21	NET OPERATING INCOME	(712)	829	1,094	185	64	1,968	-	3,429

AmerenIP - Gas
Adjustments to Operating Income
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Transportation Fuel costs (St. Ex. 17.0 Sch 17.01 IP-G)	(Source)	Maintenance of Mains (St. Ex. 17.0 Sch 17.04 IP-G)	Lobbying Expense (St. Ex. 18.0R Sch 18.01 IP-G)	Remove Transmission Plant (St. Ex.18.0R Sch 18.02 IP-G)	Industry Association Dues (St. Ex. 18.0R Sch 18.03 IP-G)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas Service Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Production Expenses	-	-	-	-	-	-	-	-
6	Storage,Term., and Proc. Expenses	-	-		-	-	-	-	-
7	Transmission Expenses	-	-	-	-	-	-	-	-
8	Distribution Expenses	-	(72)	-	(665)	-	-	-	(737)
9	Cust. Accounts,Service & Sales	-	-	-		-	-	-	-
10	Admin. & General Expenses	(3,333)		-	-	(1)	-	(96)	(3,430)
11	Depreciation & Amort. Expense	(3,391)	-	-	-	-	(6)		(3,397)
12	Taxes Other Than Income	(151)	-	-	-	-	-	-	(151)
13	-	-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	(6,876)	(72)	-	(665)	(1)	(6)	(96)	(7,716)
17	State Income Tax	635	5	-	49	-	-	7	696
18	Federal Income Tax	2,812	23	-	216	-	2	31	3,084
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	(3,429)	(44)	-	(400)	(1)	(4)	(58)	(3,936)
21	NET OPERATING INCOME	$ 3,429	$ 44	$ -	$ 400	$ 1	$ 4	$ 58	$ 3,936

AmerenIP - Gas
Adjustments to Operating Income
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Customer Service & Info. Expense (St. Ex. 18.0R Sch 18.04 IP-G)	Demonstrating & Selling Exp. (St. Ex. 18.0R Sch 18.06 IP-G)	Gas Tapping Fee (St. Ex. 18.0R Sch 18.07 IP-G)	(Source)	(Source)	(Source)	Total Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas Service Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Production Expenses	-	-	-	-	-	-	-	-
6	Storage,Term., and Proc. Expenses	-	-	-	-	-	-	-	-
7	Transmission Expenses	-	-	-	-	-	-	-	-
8	Distribution Expenses	(737)	-	-	-	-		-	(737)
9	Cust. Accounts,Service & Sales	-	(1)	-	-	-		-	(1)
10	Admin. & General Expenses	(3,430)		(25)			-	-	(3,455)
11	Depreciation & Amort. Expense	(3,397)	-	-	(9)		-	-	(3,406)
12	Taxes Other Than Income	(151)	-	-	-	-	-	-	(151)
13	-	-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-
15	Total Operating Expense								
16	Before Income Taxes	(7,716)	(1)	(25)	(9)	-	-	-	(7,751)
17	State Income Tax	696	-	2	1	-	-	-	699
18	Federal Income Tax	3,084	-	8	3	-	-	-	3,095
19	-	-	-	-	-	-	-	-	-
20	Total Operating Expenses	(3,936)	(1)	(15)	(5)	-	-	-	(3,957)
21	NET OPERATING INCOME	$ 3,936	$ 1	$ 15	$ 5	$ -	$ -	$ -	$ 3,957

AmerenIP - Gas
Rate Base
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Company Rebuttal Rate Base (Ex. 30.3, Sch.2)	Staff Adjustments (Appendix F page 7)	Staff Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Plant in Service	$ 999,190	$ (7,887)	$ 991,303
2	Accumulated Depreciation	(506,394)	(844)	(507,238)
3	-	-	-	-
4	Net Plant	492,796	(8,731)	484,065
5	Additions to Rate Base			
6	Cash Working Capital	10,396	(3,428)	6,968
7	Materials & Supplies Inventory	92,893	(17,761)	75,132
8	Gas Stored Underground - Non-Current	-	(422)	(422)
9	-	-	-	-
10	-	-	-	-
11	-	-	-	-
12	-	-	-	-
13	-	-	-	-
14	-	-	-	-
15	-	-	-	-
16	Deductions From Rate Base			
17	Customer Advances	(16,954)	-	(16,954)
18	Accumulated Deferred Income Taxes	(23,577)	425	(23,152)
19	Customer Deposits	(4,501)	-	(4,501)
20	Accrued OPEB, net of ADIT	(7,696)	(1,195)	(8,891)
21	-	-	-	-
22	-	-	-	-
23	Rate Base	$ 543,357	$ (31,112)	$ 512,245

AmerenIP - Gas
Adjustments to Rate Base
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Incentive Compensation (St. Ex. 15.0 Sch 15.07 IP-G)	Cash Working Capital (Appendix F page 10)	Hillsboro Used & Useful Adjustment (St. Ex. 15.0 Sch 15.13 IP-G)	Pro Forma Plant Additions (St. Ex. 16.0 Sch 16.01 IP-G Corrected)	Remove Transmission Plant (St. Ex. 18.0R Sch 18.02 IP-G)	Gas Tapping Fee (St. Ex. 18.0R Sch 18.07 IP-G)	Materials & Supplies (Appendix F page 18)	Subtotal Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Plant in Service	$ (527)	$ -	$ (2,157)	$ (4,187)	$ (322)	$ (694)	$ -	$ (7,887)
2	Accumulated Depreciation	(18)	-	709	(1,706)	162	9	-	(844)
3	-	-	-	-	-	-	-	-	-
4	Net Plant	(545)	-	(1,448)	(5,893)	(160)	(685)	-	(8,731)
	-								
5	Additions to Rate Base								-
6	Cash Working Capital	-	(3,428)	-	-	-		-	(3,428)
7	Materials & Supplies Inventory	-		-	-	-	-	(17,761)	(17,761)
8	Gas Stored Underground - Non-Current	-		(422)	-	-	-	-	(422)
9	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-
16	Deductions From Rate Base	-	-	-	-	-	-	-	-
17	Customer Advances	-	-	-	-	-	-	-	-
18	Accumulated Deferred Income Taxes	11	-	164	216	8	26	-	425
19	Customer Deposits	-	-	-	-	-	-	-	-
20	Accrued OPEB, net of ADIT	-	-	-	-	-	-	-	-
21	-	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-
	-								
23	Rate Base	$ (534)	$ (3,428)	$ (1,706)	$ (5,677)	$ (152)	$ (659)	$ (17,761)	$ (29,917)

AmerenIP - Gas
Adjustments to Rate Base
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Subtotal Rate Base Adjustments	Accrued OPEB Liability (St. Ex. 15.0 Sch 15.14 IP-G)	(Source)	(Source)	(Source)	(Source)	(Source)	Total Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Plant in Service	$ (7,887)	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,887)
2	Accumulated Depreciation	(844)	-	-	-	-	-	-	(844)
3	-	-	-	-	-	-	-	-	-
4	Net Plant	(8,731)	-	-	-	-	-	-	(8,731)
	-								
5	Additions to Rate Base								-
6	Cash Working Capital	(3,428)	-	-	-	-	-	-	(3,428)
7	Materials & Supplies Inventory	(17,761)	-	-	-	-	-	-	(17,761)
8	Gas Stored Underground - Non-Current	(422)	-	-	-	-	-	-	(422)
9	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-
16	Deductions From Rate Base	-	-	-	-	-	-	-	
17	Customer Advances	-	-	-	-	-	-	-	-
18	Accumulated Deferred Income Taxes	425	-	-	-	-	-	-	425
19	Customer Deposits	-	-	-	-	-	-	-	-
20	Accrued OPEB, net of ADIT	-	(1,195)	-	-	-	-	-	(1,195)
21	-	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-
	-								
23	Rate Base	$ (29,917)	$ (1,195)	$ -	$ -	$ -	$ -	$ -	$ (31,112)

AmerenIP - Gas
Interest Synchronization Adjustment
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Amount	
	(a)	(b)	
1	Gross Plant in Service	$ 512,245	(1)
2	Net Non-used and Useful Investment - Hillsboro Storage Field	1,706	(4)
3	Rate Base Plus Net Non-used and Useful Investment	513,951	
2	Weighted Cost of Debt	4.41%	(2)
3	Synchronized Interest Per Staff	22,665	
4	Company Interest Expense	24,457	(3)
5	Increase (Decrease) in Interest Expense	(1,792)	
6	Increase (Decrease) in State Income Tax Expense		
7	at 7.300%	$ 131	
8	Increase (Decrease) in Federal Income Tax Expense		
9	at 35.000%	$ 581	

(1) Source: Appendix F, page 5, column (d), Line 23
(2) Source: ICC Staff Exhibit 19.0R, Schedule 19.01 IP.
(3) Source: Ameren Exhibit 30.3 Schedule 3
(4) Source: ICC Staff Exhibit 15.0, Schedule 15.13 IP-G, page 1, Column (f), line 5.

AmerenIP - Gas
Gross Revenue Conversion Factor
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(a)	(b)	(c)	(d)
1	Revenues		1.000000	
2	Uncollectibles	1.6814%	0.016814	
3	State Taxable Income		0.983186	1.000000
4	State Income Tax	7.3000%	0.071773	0.073000
5	Federal Taxable Income		0.911413	0.927000
6	Federal Income Tax	35.0000%	0.318995	0.324450
7	Operating Income		0.592418	0.602550
8	Gross Revenue Conversion Factor Per Staff		1.687997	1.659613

Ameren/IP Gas
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Description (a)	Amount (b)	Source (c)
1	Cash Working Capital per Staff	$ 6,968	Appendix F, Page 11, Column e, Line 22
2	Cash Working Capital per Company	10,396	Ameren Exhibit 30.3, Schedule 2, page 3, column (G), line 30
3	Difference -- Staff Adjustment	$ (3,428)	Line 1 minus Line 2

Ameren/IP Gas
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Item (a)	Amount (b)	Lag (Lead) (c)	CWC Factor (d) (c/365)	CWC Requirement (e) (b*d)	Column C Source (f)
1	Revenues	$ 575,461	46.530	0.12748	$ 73,359	Appendix F, Page 12, Column b, Line 6
2	Pass-through Taxes	26,335	0.000	0.00000	-	Line 11 + Line 13 + Line 14 + Line 16 below
3	Total Receipts	$ 601,796				Line 1 + Line 2
4	Employee Benefits	$ 9,104	(17.570)	(0.04814)	(438)	Appendix F, Page 13, Column b, Line 15
5	Payroll	29,952	(12.920)	(0.03540)	(1,060)	Appendix F, Page 13, Column b, Line 5
6	PGA Purchases	456,359	(39.420)	(0.10800)	(49,287)	Company Schedule B-8, Column F, Line 3
7	Other Operations and Maintenance	37,076	(51.070)	(0.13992)	(5,188)	Appendix F, Page 12, Column b, Line 16
8	FICA	1,329	(14.740)	(0.04038)	(54)	Appendix F, Page 13, Column b, Line 11
9	Federal Unemployment Tax	26	(76.380)	(0.20926)	(5)	Company Schedule C-18, Column G, Line 3
10	State Unemployment Tax	153	(76.380)	(0.20926)	(32)	Company Schedule C-18, Column G, Line 7
11	ICC Gas Revenue Tax	494	27.470	0.07526	37	Company Schedule C-18, Column G, Line 10
12	Invested Capital Tax	3,473	(30.130)	(0.08255)	(287)	Company Schedule C-18, Column G, Line 12
13	Gross Receipts/Municipal Utility Tax	10,173	(45.630)	(0.12501)	(1,272)	Company Schedule C-18, Column G, Line 16
14	Energy Assistance Tax	3,868	(42.280)	(0.11584)	(448)	Company Schedule C-18, Column E, Line 11
15	Corporation Franchise Tax	304	(191.530)	(0.52474)	(160)	Company Schedule C-18, Column G, Line 8
16	Illinois Gas Use and Gas Revenue Tax	11,800	(29.420)	(0.08060)	(951)	Company Schedule C-18, Column E, Line 5
17	Property/Real Estate Tax	464	(392.700)	(1.07589)	(499)	Company Schedule C-18, Column G, Line15
18	Interest Expense	21,845	(91.250)	(0.25000)	(5,461)	Appendix F, Page 8, Line 3 - line 19
19	Bank Facility Fees	820	97.650	0.26753	219	Appendix F, Page 5, Column d, line 23 times Bank Facility Fees Weighted Component Sched. 19.01
20	Federal Income Tax	11,793	(38.000)	(0.10411)	(1,228)	Appendix F, Page 1, Column i, Line 18
21	State Income Tax	2,657	(38.000)	(0.10411)	(277)	Appendix F, Page 1, Column i, Line 17
22	Total Outlays	$ 601,690				Sum of Lines 4 through 21
23	Cash Working Capital per Staff				$ 6,968	Sum of Lines 1 through 21

Ameren/IP Gas
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Revenues (a)	Amount (b)	Source (c)
1	Total Operating Revenues	$ 165,479	Appendix F, Page 1, Column i, Line 3
2	PGA Purchases	456,359	Company Schedule B-8, Column F, Line 3
3	Uncollectible Accounts	(2,782)	Appendix F, Page 1, Column i, Line 4
4	Depreciation & Amortization	(21,620)	Appendix F, Page 1, Column i, Line 11
5	Return on Equity	(21,975)	Line 9 below
6	Total Revenues for CWC calculation	$ 575,461	Sum of Lines 1 through 5
7	Total Rate Base	$ 512,245	Appendix F, Page 5, Column d, Line 23
8	Weighted Cost of Capital	4.29%	ICC Staff Ex. 19.0R, Schedule 19.01 IP
9	Return on Equity	$ 21,975	Line 7 times Line 8
10	Operating Expense Before Income Taxes	$ 106,463	Appendix F, Page 1, Column i, Line 16
11	Employee Benefits Expense	(9,104)	Appendix F, Page 13, Column b, Line 15
12	Payroll Expense	(29,952)	Appendix F, Page 13, Column b, Line 5
13	Uncollectible Accounts	(2,782)	Appendix F, Page 1, Column i, Line 4
14	Depreciation & Amortization	(21,620)	Appendix F, Page 1, Column i, Line 11
15	Taxes Other Than Income	(5,930)	Appendix F, Page 1, Column i, Line 12
16	Other Operations & Maintenance for CWC Calculation	$ 37,076	Sum of Lines 10 through 15

Ameren/IP Gas
Adjustment to Cash Working Capital
For the Test Year Ending 12/31/2008
(In Thousands)

Line	Description (a)	Amount (b)	Source (c)
1	Direct Payroll per Company Filing	$ 32,373	Company Schedule B-8, Column F, Line 2
2	Staff Labor Adjustment	(970)	ICC Staff Ex. 1.0, Sch. 1.09 IP-G, Line 3
3	Adjustment for Incentive Compensation	(1,225)	ICC Staff Ex. 15.0, Sch. 15.07 IP-G, Page 1, Line 6
4	Adjustment for Workforce Reduction	(226)	Appendix F, Page 14, Line 3
5	Direct Payroll per Staff	$ 29,952	Sum of Lines 1 through 4
6	FICA Tax per Company Filing	$ 1,553	Company Schedule C-18, Column G, Line 2
7	Labor Adjustment	(74)	ICC Staff Ex. 1.0, Sch. 1.09 IP-G, Line 5
8	Incentive Compensation Adjustment	(134)	ICC Staff Ex. 15.0, Sch. 15.07 IP-G, Page 1, Line 20
9	Adjustment for Workforce Reduction	(17)	Appendix F, Page 14, Line 7
10	Company FICA Correction Adjustment	1	ICC Staff Ex. 1.0, Sch. 1.11 IP-G, Line 13
11	FICA Tax per Staff	$ 1,329	Sum of Lines 6 through 10
12	Employee Benefits per Company Filing	$ 10,986	Company Schedule B-8, Column F, Line 1
13	Adjustment for Workforce Reduction	(65)	Appendix F, Page 14, Line 6
14	Staff Adjustment	(1,817)	ICC Staff Ex. 15.0, Sch. 15.09 IP-G, Line 9
15	Employee Benefits per Staff	$ 9,104	Sum of Lines 12 through 14

AmerenIP - Gas
Adjustment for Workforce Reduction
For the Test Year Ending 12/31/2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(d)
1	Staff Proposed Compensation Savings	$ (226)	Appendix F, Page 15, line 10
2	Company CompensationSavings Rebuttal	-	
3	**Staff Proposed Adjustment**	$ (226)	
4	Staff Pension & Benefits Proposed Savings	$ (65)	Appendix F, Page 15, line 15
5	Company Pension & Benefits Savings Rebuttal	-	
6	**Staff Proposed Adjustment**	$ (65)	
7	**Taxes Other Than Income Adjustment**	$ (17)	Appendix F, Page 15, line 11

AmerenIP - Gas
Adjustment for Workforce Reduction
For the Test Year Ending 12/31/2008
(In Dollars)

Line No.	Description	AIU Amount	AMS Amount	Source
	(a)	(b)	(c)	(d)
1	Salaries (Involuntary)	$ 23,531	$ 101,892	Company Exhibit 51.9 workpaper
2	Salaries (Voluntary)	-	94,650	Company responses to Staff data requests TEE 18.02
3	Total Salaries	$ 23,531	$ 196,542	
4	Incentive Compensation (Involuntary)	$ 1,883	$ 12,079	Company Exhibit 51.9 workpaper
5	Incentive Compensation (Voluntary)	-	19,356	Company responses to Staff data requests TEE 18.02
6	Total Incentive Compensation	$ 1,883	$ 31,435	
7	Percent of Total IC in Revenue Requirement	19%	19%	Line 18
8	Total Incentive Compensation	$ 359	$ 5,988	Line 9 * Line 10
9	Jurisdictional Compensation Savings for AIU and AMS	$ 23,890	$ 202,530	Sum of Lines 3, 8
10	**Total Jurisdictional Compensation Savings**	**$ 226,419**		Total of Line 9 for AIU Amount and AMS Amount
11	**Payroll related to Net Savings**	**$ 17,321**		Line 10 times 7.65%
12	Pensions and Benefits (Involuntary)	$ 6,946	$ 30,079	Company Exhibit 51.9 workpaper
13	Pensions and Benefits (Voluntary)	-	27,941	Company responses to Staff data requests TEE 18.02
14	Total Pensions and Benefits	$ 6,946	$ 58,020	
15	**Total Jurisdictional Pension & Benefits Savings**	**$ 64,966**		
16	Expensed Incentive Compensation per Staff	$ 404		Staff Ex. 15.0, Schedule 15.07, page 2, line 9, col. (g)
17	Expensed Incentive Compensation per Company Direct	$ 2,121		Company Exhibit 51.9 workpaper
18	Percent of Total IC in Revenue Requirement	19%		Line 16 / Line 17

AmerenIP
Gas
For the test Year Ended December 31, 2008
Adjustment to Regulatory Asset Amortization
In Thousands

No.	Description	Amount	Source
	(a)	(b)	(c)
1	Amortization of Regulatory Asset per Staff	$ 1,634	Appendix F, Page 17, col. (b), line 11
2	Amortization of Regulatory Asset per Company	4,901	Co. WPC 2.22
3	Difference-Staff Adjustment	$ (3,267)	Line 1 - line 2

AmerenIP
Gas
For the test Year Ended December 31, 2008
Adjustment to Regulatory Asset Amortization
In Thousands

Line No.	Description (a)	Amount (b)	Source (c)
1	Annual Amortization	$ 16,750	Docket No. 04-0294
2	Monthly Amortization	1,396	Line 1 / 12
3	Number of months in 2010 Docket No. 09-0306 (Cons.) rates to be in effect	8	June 2010-December 2010
4	Amount to be Amortized in 2010	$ 11,167	Line 2 x line 3
5	Number of Years Docket No. 09-0306 (Cons.) expected to be in effect	2	AmerenIP WPC-10
6	Amortization Amount	$ 5,583	Line 4 / line 5
	Allocation by Rate Base		
7	Electric Rate Base-Docket No. 07-0585	$ 1,254	AmerenIP WPC-2.22
8	Gas rate Base- Docket No. 07-0585	519	AmerenIP WPC-2.22
9	Combined Rate Base 07-0585	$ 1,773	Line 7 + line 8
10	Gas Rate Base Percentage	29.26%	Line 8 / line 9
11	Gas Amortization Amount	$ 1,634	Line 6 x line 10

AmerenIP Gas
Adjustment to Materials & Supplies (Including Gas in Storage)
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
1	Materials & Supplies (Including Gas in Storage) per Staff	$ 75,132	Appendix F, Page 19, Line 9, Col. (b)
2	Materials & Supplies (Including Gas in Storage) per Company	92,893	Ameren Exhibit 30.3, Schedule 2, page 1, Line 7, Col. (d)
3	Staff Adjustment	$ (17,761)	Line 1 - line 2

AmerenIP Gas
Adjustment to Materials & Supplies (Including Gas in Storage)
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
	General Materials and Supplies		
1	Accounts Payable Percentage related to Materials & Supplies	10.53%	ICC Staff Exhibit B
2	General materials & Supplies per Company	4,106	Ameren Exhibit 30.8 IP G, Page 3, Line 1, Col. (b)
3	Accounts Payable related to Materials & Supplies	432	Line 1 x Line 2
4	General Materials & Supplies Net of Related Accounts Payable	3,674	Line 2 - Line 3
	Gas in Storage		
5	Accounts Payable Percentage related to Gas in Storage	6.63%	ICC Staff Exhibit B
6	13-Month Average of Gas in Storage per Staff	76,532	Appendix F, Page 20, Column (b), Line 3
7	Accounts Payable related to Gas in Storage	5,074	Line 5 x Line 6
8	Gas in Storage Net of Related Accounts Payable	71,458	Line 6 - Line 7
9	Total Materials & Supplies (Including Gas in Storage) per Staff	75,132	Line 4 + Line 8

AmerenIP Gas
Adjustment to Materials & Supplies (Including Gas in Storage)
For the Test Year Ending December 31, 2008
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
1	13-month Average Balance Gas in Storage per Company	$ 88,787	Ameren Exhibit 30.8 IP G, Page 3, Line 2, Col. (b)
2	Adjustment to 13-month Average Balance Gas in Storage	(12,255)	ICC Staff Exhibit 25.0, Schedule 25.03 IP-G
3	13-month Average Balance Gas in Storage per Staff	$ 76,532	Line 1 + line 2

Daily Cash Balances, Money Pool Transactions and Availability under Credit Facilities for AmerenIP and AmerenCIPS
October 17, 2008 through March 31, 2009

	AmerenIP			AmerenCIPS		
(A)	(B)	(C)	(D)	(E)	(F)	(G)
Date	Cash & Investments[1]	Net Money Pool Contributions (Borrowings) (millions $)	Available Capacity under Credit Facilities[2]	Cash & Investments[1]	Net Money Pool Contributions (Borrowings) (millions $)	Available Capacity under Credit Facilities[2]
10/17/08						
10/18/08	This information has been redacted.					
10/19/08						
10/20/08						
10/21/08						
10/22/08						
10/23/08						
10/24/08						
10/25/08						
10/26/08						
10/27/08						
10/28/08						
10/29/08						
10/30/08						
10/31/08						
11/01/08						
11/02/08						
11/03/08						
11/04/08						
11/05/08						
11/06/08						
11/07/08						
11/08/08						
11/09/08						
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11/11/08						
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11/15/08						
11/16/08						
11/17/08						
11/18/08						
11/19/08						
11/20/08						
11/21/08						

	AmerenIP			AmerenCIPS		
(A)	(B)	(C)	(D)	(E)	(F)	(G)
Date	Cash & Investments[1]	Net Money Pool Contributions (Borrowings) (millions $)	Available Capacity under Credit Facilities[2]	Cash & Investments[1]	Net Money Pool Contributions (Borrowings) (millions $)	Available Capacity under Credit Facilities[2]
11/22/08						
11/23/08	This information has been redacted.					
11/24/08						
11/25/08						
11/26/08						
11/27/08						
11/28/08						
11/29/08						
11/30/08						
12/01/08						
12/02/08						
12/03/08						
12/04/08						
12/05/08						
12/06/08						
12/07/08						
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12/09/08						
12/10/08						
12/11/08						
12/12/08						
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12/24/08						
12/25/08						
12/26/08						
12/27/08						
12/28/08						
12/29/08						
12/30/08						
12/31/08	50.2	44.3	350.0	0.3	(44.1)	72.7

	AmerenIP			AmerenCIPS		
(A)	(B)	(C)	(D)	(E)	(F)	(G)
Date	Cash & Investments[1]	Net Money Pool Contributions (Borrowings) (millions $)	Available Capacity under Credit Facilities[2]	Cash & Investments[1]	Net Money Pool Contributions (Borrowings) (millions $)	Available Capacity under Credit Facilities[2]
01/01/09						
01/02/09			This information has been redacted.			
01/03/09						
01/04/09						
01/05/09						
01/06/09						
01/07/09						
01/08/09						
01/09/09						
01/10/09						
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02/04/09						
02/05/09						
02/06/09						
02/07/09						
02/08/09						
02/09/09						

	AmerenIP			AmerenCIPS		
(A)	(B)	(C)	(D)	(E)	(F)	(G)
Date	Cash & Investments[1]	Net Money Pool Contributions (Borrowings) (millions $)	Available Capacity under Credit Facilities[2]	Cash & Investments[1]	Net Money Pool Contributions (Borrowings) (millions $)	Available Capacity under Credit Facilities[2]
02/10/09						
02/11/09			This information has been redacted.			
02/12/09						
02/13/09						
02/14/09						
02/15/09						
02/16/09						
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02/18/09						
02/19/09						
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02/26/09						
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03/18/09						
03/19/09						
03/20/09						
03/21/09						

	AmerenIP			AmerenCIPS		
(A)	(B)	(C)	(D)	(E)	(F)	(G)
Date	Cash & Investments[1]	Net Money Pool Contributions (Borrowings) (millions $)	Available Capacity under Credit Facilities[2]	Cash & Investments[1]	Net Money Pool Contributions (Borrowings) (millions $)	Available Capacity under Credit Facilities[2]
03/22/09						
03/23/09	This information has been redacted.					
03/24/09						
03/25/09						
03/26/09						
03/27/09						
03/28/09						
03/29/09						
03/30/09						
03/31/09	179.2	55.5	350.0	0.1	(55.5)	135.0

[1] Excludes amounts posted as collateral or contributions to the AIU money pool.

[2] The credit facility sub-limits for IP and CIPS are $350 million and $135 million, respectively.

[3] $x.x million is the net effect of IP's $xx.x million contribution (for CIPS' benefit), less the $xx million IP simultaneously borrowed from Ameren.

[4] $x is the net effect of IP's $xx million contriubtion (for CIPS' benefit), less the $xx million IP simultaneously borrowed from Ameren.

Sources:

Staff Group Cross Ex. 1, "IL Facilities Borrowing," (O'Bryan WP 2)
ICC Staff Ex. 19.0R, p. 10