STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Central Illinois Light Company d/b/a AmerenCILCO	:	
	:	**07-0585**
Proposed general increase in electric delivery service rates.	:	
Central Illinois Public Service Company d/b/a AmerenCIPS	:	
	:	**07-0586**
Proposed general increase in electric delivery service rates.	:	
Illinois Power Company d/b/a AmerenIP	:	
	:	**07-0587**
Proposed general increase in electric delivery service rates.	:	
Central Illinois Light Company d/b/a AmerenCILCO	:	
	:	**07-0588**
Proposed general increase in gas delivery service rates.	:	
Central Illinois Public Service Company d/b/a AmerenCIPS	:	
	:	**07-0589**
Proposed general increase in gas delivery service rates.	:	
Illinois Power Company d/b/a AmerenIP	:	
	:	**07-0590**
Proposed general increase in gas delivery service rates.	:	**(Cons.)**

<u>ORDER</u>

DATED: September 24, 2008

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	:	**07-0590**
Proposed general increase in gas delivery service rates.	:	**(Cons.)**

ORDER

By the Commission:

I. PROCEDURAL BACKGROUND

On November 2, 2007, Central Illinois Light Company d/b/a AmerenCILCO ("AmerenCILCO"), Central Illinois Public Service Company d/b/a AmerenCIPS

("AmerenCIPS"), and Illinois Power Company d/b/a AmerenIP ("AmerenIP") each filed with the Illinois Commerce Commission ("Commission") new and/or revised tariff sheets for electric and gas service. AmerenCILCO, AmerenCIPS, and AmerenIP are each a wholly owned subsidiary of Ameren Corporation ("Ameren") providing residential, commercial, and industrial electric and gas service throughout their respective service areas. AmerenCILCO, AmerenCIPS, and AmerenIP are collectively hereinafter referred to as Ameren Illinois Utilities ("AIU"). The new and revised tariff sheets ("Proposed Tariffs") proposed changes in electric and gas rates and the establishment of new riders, to be effective December 17, 2007. On December 5, 2007, the Commission entered six Suspension Orders suspending the Proposed Tariffs for each company to and including March 30, 2008 in accordance with Section 9-201(b) of the Public Utilities Act ("Act"), 220 ILCS 5/1-101 et seq. The Suspension Orders identify the specific tariff sheets filed by AIU. Upon suspension, AmerenCILCO's electric and gas filings became identified as Docket Nos. 07-0585 and 07-0588, respectively; AmerenCIPS' electric and gas filings became identified as Docket Nos. 07-0586 and 07-0589, respectively; and AmerenIP's electric and gas filings became identified as Docket Nos. 07-0587 and 07-0590, respectively. On March 12, 2008, the Commission entered Resuspension Orders renewing the suspension of the Proposed Tariffs to and including September 30, 2008.

Notice of the filing of the proposed rate increases was posted in each of AIU's business offices and was published twice in newspapers of general circulation within each of AIU's service areas, in accordance with the requirements of Section 9-201(a) of the Act, and the provisions of 83 Ill. Adm. Code 255, "Notice Requirements for Change in Rates for Cooling, Electric, Gas, Heating, Telecommunications, Sewer or Water Services." In addition, AIU sent notice of the filing to its customers in a bill insert.

On December 4, 2007, AIU was notified of certain deficiencies in its filings in accordance with 83 Ill. Adm. Code 285, "Standard Information Requirements for Public Utilities and Telecommunications Carriers in Filing for an Increase in Rates" ("Part 285"). The deficiency letters required AIU to submit various missing information and provide explanations of certain portions of the rate filings. AIU provided information in response to the deficiency letters on January 4, 2008.

Petitions seeking leave to intervene were filed by the People of the State of Illinois through the Attorney General ("AG"), the Cities of Bloomington, Champaign, Decatur, Monticello, and Urbana and the Town of Normal (collectively referred to herein as the Local Government Interveners ("LGI")), Citizens Utility Board ("CUB"), AARP,[1] System Council U-05 of the International Brotherhood of Electrical Workers, an association consisting of Local Unions 51, 309, 649, 702, and 1306 ("IBEW"), Grain and Feed Association of Illinois ("GFA"), Kroger Company ("Kroger"), Constellation NewEnergy-Gas Division, LLC ("CNE-Gas"), Constellation Energy Commodities Group, Inc., Vanguard Energy Services, LLC, and the Coalition of Energy Suppliers, which consists of Constellation NewEnergy, Inc., Direct Energy Services, LLC, Integrys

[1] In 1999, the "American Association of Retired Persons" changed its name to simply "AARP," in recognition of the fact that people do not have to be retired to be members.

Energy Services Corporation, and MidAmerican Energy Company. The University of Illinois, Air Products and Chemicals Company, ArcelorMittal Steel Company, Cargill, Inc., Caterpillar, Inc., Enbridge Energy, LLC, GBC Metals, LLC, Illinois Cement Company, PPG Industries, Inc., Tate and Lyle Ingredients Americas, Inc., and Viscofan USA, Inc. also intervened as members of the Illinois Industrial Energy Consumers ("IIEC"). The Commercial Group, an ad hoc association of retail companies that own and operate retail stores in the service areas of AIU intervened as well. For purposes of this proceeding, the Commercial Group consists of Best Buy Company, Inc., JC Penny Corporation, Inc., Macy's, Inc., and Wal-Mart Stores, Inc. All of the petitions to intervene were granted. Commission Staff ("Staff") participated as well.

On February 6, February 11, February 13, February 19, February 26, and February 28, 2008, a public forum was held in Marion, Decatur, Belleville, Peoria, Quincy, and Champaign, respectively, for the purpose of receiving public comment on the general increase in electric and gas rates proposed by AIU. These locations were selected because they represent some of the larger population centers in the AIU service areas. A transcript of each public forum was made and is available on the Commission's e-Docket system.

Pursuant to due notice, status hearings were held in this matter before duly authorized Administrative Law Judges of the Commission at its offices in Springfield, Illinois on January 3 and June 3, 2008. Thereafter, evidentiary hearings were held on June 9 through June 13, 2008. Following the Commission's ruling on a petition for interlocutory review, an additional evidentiary hearing was held on July 1, 2008. Appearances were entered by counsel on behalf of AIU, Staff, the AG, LGI, CUB, AARP, GFA, IIEC, Kroger, the Commercial Group, and CNE-Gas. The record was marked "Heard and Taken" on August 11, 2008. Following the submission of AIU's response to a Post-Record Data Request by the Administrative Law Judges pursuant to Section 200.875 of 83 Ill. Adm. Code 200, "Rules of Practice," the record was reopened for the purpose of admitting said response and the Staff reply into the record. The record was again marked "Heard and Taken" on September 3, 2008.

At the evidentiary hearings, AIU called 33 witnesses to testify. The 33 witnesses include (1) Michael Adams, a Vice President with Concentric Energy Advisors, Inc. ("Concentric"),[2] (2) Mary Batcher, Tax National Director for Statistics and Sampling at Ernst & Young LLP, (3) Krista Bauer, Manager of Compensation and Performance for Ameren Services Company ("AMS"),[3] (4) Scott Cisel, Chief Executive Operating Officer of each AIU company, (5) Stephen Colyer, Director of Gas Operations for each AIU company, (6) Wilbon Cooper, a Manager of Rate Engineering and Analysis within AMS' Regulatory Policy and Planning Department, (7) Michael Getz, Managing Supervisor of

[2] Concentric is a management consulting and economic advisory firm specializing in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses and negotiations.

[3] AMS is the service company subsidiary of Ameren and provides various services to its affiliates, including AIU.

Business Performance for AMS, (8) Scott Glaeser, Vice President of Gas Supply and System Control for the Gas Supply Division of AmerenEnergy Fuels and Services Company, (9) Philip Hanser, a principal in The Brattle Group, an economic consulting firm, (10) Laurie Karman, Managing Supervisor of Credit and Collections for AMS, (11) Leonard Jones, Managing Supervisor of Restructured Services within AMS' Regulatory Policy and Planning Department, (12) Charles Laderoute, President of the consulting firm Charles D. Laderoute, Ltd., (13) Mark Livasy, Superintendent of Energy Delivery Illinois for each AIU company, (14) Martin Lyons, Vice President and Controller of AMS and each AIU company, (15) Keith Martin, Manager of Customer Service and Energy Efficiency for each AIU company, (16) Kathleen McShane, President of the economic consulting firm Foster Associates, Inc., (17) Robert Mill, Director of AMS' Regulatory Policy and Planning Department, (18) Timothy Moloney, Managing Supervisor in AMS' Credit Risk Management Department, (19) Joseph Mullenschlader, Manager of Corporate Security for AMS, (20) Craig Nelson, Vice President of Regulatory Affairs and Financial Services of each AIU company, (21) Michael O'Bryan, Senior Capital Markets Specialist in Treasury-Corporate Finance of AMS, (22) Ronald Pate, Vice President of Regional Operations for each AIU company, (23) Robert Porter, Manager of Acquisitions for AMS, (24) Ronald Stafford, Managing Supervisor of Regulatory Accounting in AMS' Controller's Function, (25) Bruce Steinke, Vice President and Controller of Ameren, AMS, and each AIU company, (26) David Strawhun, a Career Engineer in Distribution System Planning for AMS, (27) John Taylor, a consultant with Concentric, (28) Stephen Underwood, Manger of Gas Storage for AMS, (29) William Warwick, Managing Supervisor of Rate Engineering within AMS' Regulatory Policy and Planning Department, (30) Gary Weiss, Manager of Regulatory Accounting for AMS, (31) Andrew Wichmann, a Financial Specialist in AMS' Controller's Function, (32) John Wiedmayer, a Project Manager of Depreciation Studies for Gannett Fleming, Inc.,[4] and (33) Robert Willen, Supervising Engineer of the Load Analysis Group within AMS' Corporate Planning Function.

Twelve witnesses testified on behalf of Staff. The Staff witnesses include (1) Theresa Ebrey, (2) Mary Everson, and (3) Daniel Kahle, Accountants in the Accounting Department of the Financial Analysis Division of the Commission's Bureau of Public Utilities, (4) Janis Freetly and (5) Rochelle Phipps, Senior Financial Analysts in the Finance Department of the Financial Analysis Division, (6) Cheri Harden and (7) Peter Lazare, Rate Analysts in the Rates Department of the Financial Analysis Division, (8) Harry Stoller, Director of the Energy Division of the Bureau of Public Utilities, (9) Greg Rockrohr, a Senior Electrical Engineer in the Engineering Department of the Energy Division, (10) Eric Lounsberry, Supervisor of the Gas Section in the Engineering Department, (11) Dennis Anderson, a Senior Energy Engineer in the Gas Section, and (12) David Sackett, an Economic Analyst in the Policy Department of the Energy Division.

[4] Gannett Fleming, Inc. is a consulting firm that, among other things, assists clients prepare accounting and financial data for revenue requirement and cash working capital issues, allocate the cost of service among customer classes, and design customer rates.

IIEC offered five witnesses at the evidentiary hearings. IIEC's witnesses include Alan Chalfant, Michael Gorman, James Selecky, Robert Stephens, and David Stowe from the consulting firm of Brubaker & Associates, Inc.[5] David Effron, a consultant specializing in utility regulation, and Michael Brosch, a principal in the consulting firm Utilitech, Inc., testified on behalf of the AG and CUB. The AG also called Scott Rubin, an independent consultant and attorney specializing in matters affecting the public utility industry, to testify. Christopher Thomas, CUB's Director of Policy, Lynne Kiesling, a Senior Lecturer in the Department of Economics at Northwestern University, and Martin Cohen, an independent consultant specializing in regulatory policy analysis, testified on behalf of CUB. Kroger called Kevin Higgins, a principal at Energy Strategies, LLC,[6] to testify. Jeffrey Adkisson, GFA Executive Vice President and Treasurer, testified for GFA. Nancy Hughes, a principal and Senior Director with R.W. Beck, Inc.,[7] offered testimony for LGI. The Commercial Group called Richard Baudino, a consultant with the firm of J. Kennedy & Associates, Inc., to testify. James Germain, the Director of Customer Supply Management for CNE-Gas, and Lisa Rozumialski, a Manager of Gas Operations for CNE-Gas, both testified on behalf of CNE-Gas. Ralph Smith, a consultant with the accounting and regulatory consulting firm of Larkin & Associates, PLLC, testified for AARP. Paul Noble, Business Manager of IBEW Local 72 and Chairman of IBEW System Council U-05, testified on behalf of IBEW.

AIU, Staff, the AG, LGI, CUB, AARP, GFA, Kroger, CNE-Gas, the Commercial Group, and IIEC each filed an Initial Brief and Reply Brief. A Proposed Order was served on the parties. All but AARP filed a Brief on Exceptions. AIU, Staff, the AG, CUB, GFA, CNE-Gas, and IIEC each filed a Brief in Reply to Exceptions. The Briefs on Exceptions and Briefs in Reply to Exceptions have been considered in the preparation of this Order.

As a general matter, the Commission notes that in their respective Briefs on Exceptions, several parties complain that the Proposed Order did not specifically lay out each and every aspect of their argument and that in some instances the conclusion did not dispose of every aspect of, or basis underlying, each proposal. First, the Commission notes that, excluding the appendices, the proposed order is 360 pages in length and while not perfect, is generally adequate in summarizing parties' positions and arguments. Additionally, the Commission observes that Illinois courts have held that "The Commission is not required to make a finding on each evidentiary fact or claim; rather, it is sufficient that its findings are specific enough to permit an intelligent review of its decision." (City of Chicago v. Illinois Commerce Commission and Commonwealth Edison Company, 264 Ill. App. 3d 403, 409, 636 N.E.2d 709 (First District Appellate Court, 1993)) The Illinois Supreme Court further stated that "If the findings support the order, then the reviewing court examines the evidence to ascertain if the findings are supported by the facts." (Brinker Trucking Co. v. Illinois Commerce Commission, 19 Ill.

[5] Brubaker & Associates, Inc. offers consulting services in the energy, economic, and regulatory fields.
[6] Energy Strategies, LLC is a consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.
[7] R.W. Beck, Inc. offers consulting services in the areas of finance, energy, water/wastewater, and solid waste enterprises.

2d 354, 357, 166 N.E.2d 18, 20 (1960)) The Commission believes that in this lengthy and complicated Order it is not necessary to restate every aspect or basis for every argument either in the statement of a party's position or in the conclusion.

II. NATURE OF AIU'S OPERATIONS

Ameren formed in 1997 with the merger of Union Electric Company and Central Illinois Public Service Company ("CIPS"). Thereafter, Ameren acquired Central Illinois Light Company ("CILCO") in 2002 and Illinois Power Company ("IP") in 2004. The service area of AIU covers roughly the lower two-thirds of Illinois. AmerenCILCO currently serves approximately 209,313 electric customers and 212,287 gas customers. Within AmerenCIPS' footprint are two rate areas: AmerenCIPS and AmerenCIPS Metro-East. AmerenCIPS currently serves approximately 387,097 electric customers and 185,484 gas customers. The AmerenCIPS Metro-East area is the former Illinois service area of Union Electric Company d/b/a AmerenUE ("AmerenUE"). This territory was transferred to AmerenCIPS in 2005. AmerenCIPS Metro-East serves approximately 18,000 customers in the Alton area. AmerenIP currently serves approximately 614,847 electric customers and 418,700 gas customers. All of AIU's operations are within Illinois, although an affiliate of AIU (AmerenUE) provides utility service in Missouri. Other affiliates of AIU provide unregulated services.

III. AIU'S PROPOSED TEST YEAR AND REVENUES

AIU proposes to use the 12 months ending December 31, 2006 as the test year in this proceeding. No party objects to the use of this test year. The Commission concludes that the historical test year AIU proposes is appropriate for purposes of this proceeding.

The Proposed Tariffs reflect an increase in delivery service revenues for all but the gas customers of AmerenCILCO. For AmerenCILCO gas customers, AIU proposes a decrease in revenues. The proposed changes in the delivery service operating revenues for each service type and territory are as follows:[8]

	ELECTRIC		GAS	
	Revenue Change	% Change	Revenue Change	% Change
AmerenCILCO	$10,151,000	8.22	-$3,851,310	-4.67
AmerenCIPS	$30,847,000	14.49	$14,396,496	22.11
AmerenIP	$139,320,000	39.12	$55,912,346	41.84

AIU determined these revenues using an 11.00% cost of equity. Since the proposed increase for AmerenIP electric customers is comparatively higher, for the first year that

[8] The numbers contained in the table reflect only proposed delivery service revenues since it is only those revenues at issue in this proceeding.

new rates are in effect, AIU proposes to limit the increase to an 8.5% increase in *bundled* rates for the residential customer class as a whole, based on current power supply costs.

AIU's last electric delivery service rate cases were consolidated Docket Nos. 06-0070, 06-0071, and 06-0072. AmerenCILCO's last gas rate case was Docket No. 02-0837. AmerenCIPS' last gas rate case was Docket No. 03-0008. AmerenIP's last gas rate case was Docket No. 04-0476.

IV. RATE BASE

A. Introduction

The rate base represents the net level of investment that a utility company has dedicated to public service on which it is entitled to earn a return. The rate base consists principally of book investment in utility plant and working capital, less deductions to reflect other sources of funds, such as deferred taxes. Schedules showing AIU's rate base for each utility at present and recommended rates for the test year ending December 31, 2006 were presented by AIU and Staff.

B. Resolved Issues

1. Accrued OPEB Adjustment

AG/CUB witness Effron recommends an adjustment to reflect Accrued Other Post Employment Benefits ("OPEB"). AIU agrees with this proposed adjustment. The Commission finds the AG/CUB proposed adjustment reasonable and appropriate and it is hereby adopted.

2. Written Procedures for Gas Losses

Staff recommends that AIU develop written procedures for the treatment of the source and types of losses from underground storage fields. AIU agrees to work with Staff to draft clear procedures regarding the accounting treatment of gas losses. The Commission finds Staff's recommendation to develop written procedures regarding the treatment of gas losses reasonable and directs AIU to collaborate with Staff to develop such written procedures that are agreeable to both AIU and Staff.

3. Electric Material and Supplies Inventory

Staff witness Everson proposes an adjustment to electric materials and supplies inventory for the percentage of accounts payable because accounts payable represents vendor-financing. AIU agrees with this adjustment. The Commission finds Staff's proposed adjustment to electric material and supplies inventory to be reasonable and it is hereby adopted.

4. Additional Cash Working Capital

Staff witness Kahle proposes an adjustment to eliminate AIU's proposed increase to rate base for additional cash working capital ("CWC") for the electric operations related to a permanent increase in accounts receivable balances. AIU agrees to remove this proposed increase for each of the electric utilities. However, AIU, states that it reserves the right to raise this issue again in the future. The Commission finds the proposal to eliminate any increased accounts receivable balances related to electric operations reasonable and such increases should not be reflected in rate base in this proceeding.

5. Storm Recovery Costs

AIU initially proposed a pro forma adjustment to capture storm recovery costs that each of AIU's electric utilities incurred during 2006 and 2007. AIU's proposed pro forma adjustment utilized a five year amortization for these combined 2006 and 2007 storm recovery costs, and included each utility's unamortized storm recovery amounts in that utility's respective rate base. Staff witness Rockrohr recommends that the Commission reject AIU's proposed pro forma adjustment explaining that AIU's proposed rate treatment of storm recovery costs could provide a disincentive for the utility to bolster its distribution system to withstand storms. AIU agrees to modify its proposed treatment of storm recovery costs and use a six-year historical normalization period to calculate the storm recovery costs individually allowable for each of the AIU electric utilities. Mr. Rockrohr finds this alternative rate treatment of storm recovery costs described by AIU witness Stafford to be acceptable. The Commission finds AIU's amended proposal for the treatment of storm recovery costs reasonable and it is hereby adopted.

6. ADIT and Other Reserves

AG/CUB witness Effron recommends that Accumulated Deferred Income Taxes ("ADIT") be adjusted to follow the treatment of the related reserves or accruals in the determination of rate base related to Pensions and Deferred Compensation. AIU agrees with these proposed adjustments. The Commission finds the AG/CUB's adjustment to ADIT related to Pension and Deferred Compensation reasonable and it is hereby adopted.

In its Brief on Exception, the AG recommends that the Proposed Order be modified to deduct the injuries and damages reserve from rate base, arguing that these are ratepayer-supplied funds. AIU disagrees with this proposal, noting that its modification of injuries and damages expense treatment in this case from an accrual basis to a cash basis for ratemaking, based on a five-year average of cash claims paid, is similar to the recommendation of Staff in these proceedings and to how such costs were established in Docket Nos. 06-0070, 06-0071, and 06-0072 (Cons.). AIU further states that the use of a cash basis eliminates the existence of a reserve balance for ratemaking, because there is no debit to expense and credit to a reserve account, or an

advance payment to be recorded as an asset or as a negative reserve balance. In other words, a reserve balance, positive or negative, simply does not exist. It appears to the Commission that while a reserve balance still exists on the utilities' balance sheets, as the AG argues, it is only for reporting, not ratemaking, purposes. The Commission finds that the AG's proposed adjustment is not necessary for these reasons and rejects it.

7. Allocation for Common Plant for Substations

AIU allocates common facilities by primary function, in accordance with "The Illinois White Paper," adopted by the Commission in Docket No. 98-0894. While Staff witness Everson initially expressed concern with AIU's proposed allocation, she now agrees with AIU's allocation and does not propose any adjustment. The Commission finds the allocation previously decided by the Commission is appropriate and that approach is hereby adopted for purposes of allocating common plant for substations in this case.

C. Contested Issues

1. Plant Additions since Last Rate Case

a. AIU's Position

AIU states that, although it is in compliance with Commission document retention rules, certain aspects of its recordkeeping practices need to be improved to facilitate a timely and thorough review of plant additions. Moreover, AIU claims to have previously acknowledged that some of the documentation supporting plant additions was not provided to Staff as timely as it could have been. Having said this, AIU asserts that the requirement that parties engage in full and fair discovery and produce evidence in support of their position is not a one-way street.

AIU claims that despite repeated requests, Staff has never disclosed specifically which invoices were disallowed and for what reason. AIU argues that Staff's methodology for disallowing plant additions – that is, sampling a portion of additions and calculating a disallowance percentage that is applied to all additions – makes the failure to provide this information especially problematic. According to AIU, this is not a case where it has failed to document over $100 million of plant additions, as Staff's adjustment suggests. Disallowing a percentage of additions and applying that percentage to total plant additions, AIU avers, magnifies the impact of each disallowed invoice. Given that the ultimate dollar impact of each disallowed invoice is greater than any actual invoice amount, AIU claims identification of the specific invoices at issue is critical. AIU contends that Staff's failure to provide this information has prejudiced AIU. AIU argues that Staff's sampling methodology results in an overstatement of the proposed adjustment by about $111 million.

Identification of the invoices at issue, AIU claims, was accomplished through a process of elimination in which AIU "guessed" at the reason why Staff believes certain additions are allegedly unsupported. AIU says it provided documentation and explanation for every invoice that it believes Staff witness Everson disallowed. AIU states that Ameren Ex. 19.12 provides detailed information relating to approximately 1,300 invoices. Schedules 1 through 6 of the exhibit, AIU adds, list each invoice disallowed and explains why the disallowance is not appropriate. In some instances where AIU says it either could not locate an invoice or amounts did not match with the list relied on by Ms. Everson, her adjustment was accepted. In surrebuttal, AIU compiled Ameren Ex. 43.6, which revised Ameren Ex. 19.12 and provided additional invoices and more supporting documentation and explanation. Ameren Exs. 19.13 and 61.1, AIU claims, provide similar supporting data for electronic transactions. According to AIU, all of these exhibits demonstrate that the amount of plant additions AIU seeks is adequately supported. AIU asserts that Staff dismisses all of the additional support and explanation provided in rebuttal and surrebuttal.

AIU asserts that Ms. Everson employs an invoice-by-invoice approach that is at odds with Staff's approach to analyzing plant additions in other rate cases. In other cases, AIU claims Staff often looks to continuing property records and other non-invoice documentation in order to identify additions that vary significantly in comparison to a utility's prior plant addition expenditures. AIU states that in contrast to Staff's typical review, in this case, Ms. Everson demanded that the AIU provide invoice level support for all selected expenditures. In AIU's view, this approach was burdensome, unwarranted, and unnecessary.

AIU says that among other things, Staff requested a list of all projects whose total costs were above $500,000, a total of 64 projects. AIU indicates that Staff requested invoices associated with 37 of these projects, of which Staff included 35 in its sample. AIU says it collected, by various queries on AIU's general ledger systems, details of the projects within Ms. Everson's request. This information was then used to compile a list of invoices, where each invoice was associated with a unique voucher number. AIU says these voucher numbers were then used to locate the hard copies of each invoice, which were then scanned and provided to Ms. Everson for review.

AIU says Ms. Everson conducted a review of invoices to determine what percentage of these invoices, for each of the utilities, was not supported by proper documentation. Ms. Everson states that she test sampled supporting documentation for third party vendors for capital additions. She cited seven issues or deficiencies with the cost substantiation provided by AIU: (1) duplicate invoices; (2) billings to the wrong company; (3) invoices not found that correspond to the listing of invoices provided; (4) amounts on invoices that did not correspond to the listing; (5) projects not determinable from the invoice or the invoice is not related to the project; (6) illegible invoices; and (7) certain AmerenIP project amounts that were paid via electronic transfer without a supporting invoice. AIU states that Ms. Everson used her total of unsupported documentation to calculate the percentage of total project costs that is not supported. AIU says she then applied the percentage of additions for which AIU did not provide

supporting documentation to the total of plant additions to calculate her adjustment to plant additions, reducing rate base by this amount. AIU complains that at no point has Ms. Everson identified specific invoices for which she recommends disallowance or the reason for the disallowance. In its Initial Brief, AIU also describes the efforts it made to obtain information it believed it needed to evaluate Ms. Everson's proposed disallowance.

According to AIU, the most important problem undermining Ms. Everson's analysis is her failure to identify which invoices she disallowed and why. In AIU's view, this limits the ability of AIU or the Commission to confirm or refute Ms. Everson's analysis. AIU states that although its' Data Requests 5.06, 5.07, and 5.08 requested specific information identifying each invoice disallowed and the reasons for each disallowance, Staff failed to provide this information. By failing to provide the specific reason for each denied invoice, AIU says it was forced to guess at the denial reason in its attempts to explain or refute her findings.

AIU says it recognizes that it bears the initial burden of proving the reasonableness and prudence of expenditures. AIU believes it has satisfied its burden of proving its plant additions, and argues that Staff has failed to meet its burden of proving its adjustment. AIU states that the burden of proof encompasses two concepts - the burden of persuasion and the burden of production. (AIU Initial Brief at 25, citing Consolidated Communications Consultant Services, Inc. v. Illinois Bell Telephone Company, Docket No. 99-0429) According to AIU, although the burden of persuasion – the ultimate burden of persuading the tribunal that the necessary elements of a claim have been proven – is assigned at the beginning of a dispute and does not shift during the course of the proceeding, the burden of producing evidence shifts between the parties as the case proceeds, depending on the nature of specific evidence and the issue it addresses. AIU asserts that in rate cases, once a utility makes a showing of the costs necessary to provide service under its proposed rates, it has established a prima facie case, and the burden then shifts to others to show that the costs incurred by the utility are unreasonable because of inefficiency or bad faith. (AIU Initial Brief at 25, citing City of Chicago v. Illinois Commerce Commission, 478 N.E.2d 1369, 1375, (Ill. Ct. App. 1985) ("City of Chicago")) AIU claims that where Staff proposes an adjustment, Staff bears the burden of producing evidence to support the reasonableness of the adjustment. AIU contends that burden is not met by pointing the finger back to the utility and arguing that the utility has not met its burden of proof. (AIU Initial Brief at 25, citing Commonwealth Edison Company ("ComEd"), Docket Nos. 83-0537/84-0555, Order at 183-84)

According to AIU, the Commission and courts recognize that the proponent of a position has the burden of supporting its position with credible, admissible evidence. AIU believes it produced evidence supporting its plant additions. Staff did not think the evidence was good enough. AIU says Staff is free to take that position, but it is ultimately the Commission, not Staff, that determines whether a party has met its burden of proof. AIU asserts that throughout this proceeding it put forth voluminous evidence supporting plant additions.

AIU argues that Staff failed to do anything sufficient to meet its burden with respect to its proposed adjustment. AIU says Staff never conducted an investigation of AIU's records at their offices. AIU suggests that had an on-site review occurred, any questions Ms. Everson had about AIU's documentation could have been answered. AIU complains that Ms. Everson never sent additional data requests seeking information in addition to or different from the information AIU provided in response to Staff Data Requests MHE 3.01-3.06. AIU complains that apart from correcting a few errors, Ms. Everson's adjustment did not change from her direct testimony, despite the massive amount of information produced by AIU in response to her concerns.

AIU says Ms. Everson did not rebut Dr. Batcher's comments regarding Ms. Everson's lack of documentation in her rebuttal testimony. According to AIU, Dr. Batcher testified that Ms. Everson did not provide any explanation of why she did not maintain detailed records of the review of sampled costs. AIU believes this is important because the sampled costs should be available to all parties to review and either agree or contest by arguments to the regulations, sound practice, or providing additional supporting or refuting evidence. In AIU's view, it is unfair to affected parties to deny them the ability to confirm or refute determinations made about individual sampled costs. AIU says that although it may be able to guess the reasons some of the invoices were rejected and provide counter arguments or additional supporting documents, that is a poor substitute for knowing why each invoice was rejected.

AIU witness Taylor states that sampling is the application of probability theory and statistics to gain knowledge about a population of concern, by the selection and review of individual observations within this population. Audit sampling, AIU avers, is the application of sampling techniques to the goals of an audit. AIU states that an "audit" is defined as an analysis used to ascertain the validity or reliability of information. According to Statement of Auditing Standards ("SAS") No. 39 (AU 350.01): "Audit sampling is the application of an audit procedure to less than 100 percent of the items within an account balance or class of transactions for the purpose of evaluating some characteristics of the balance or class." (AIU Initial Brief at 28, citing SAS No. 39, Auditing Sampling)

According to Dr. Batcher, given the importance of having a representative sample, planning regarding an audit sample is key. The first steps, AIU avers, are to learn about the population to be sampled, the type of estimates to be made from the sample, and the precision needed. Whether a statistical or judgment sample is used, AIU says the auditor approaches the testing of account balances with the recognition that some inconsistency in the sample details is to be expected, even though the account balances are fundamentally correct because of factors such as minor clerical errors, discounts, and irretrievable documentation. According to AIU, a materiality threshold is established as part of the sample planning process in recognition of these minor inconsistencies. For example, AIU suggests a materiality threshold of 1% might be established for invoices that can not be located on current systems. If testing is of older systems that are no longer used or, invoices have been archived, AIU suggests

the threshold might be increased to something larger, like 5%, which in the auditor's judgment, makes allowance for the retrieval difficulties which do not, in and of themselves, indicate a problem with the invoice. AIU says other planning steps include consideration of the sample selection methodology, establishment of criteria for the review of selected invoices, determination of the format for documenting the individual decisions made for the selected invoices and the specific failure reason applied to each failed invoice, and the estimation, reporting, and documentation to be kept.

Dr. Batcher states that given the importance of having a representative sample, regulators often impose documentation standards. Dr. Batcher cites as examples, the Office of the Inspector General from the Department of Health and Human Services, and various state taxing authorities, as well as the Internal Revenue Service ("IRS"), which she says requires individual tracking of the results of the review of each sampled items, the estimators used, and various additional specific details.

It is Dr. Batcher's opinion that Staff has failed to provide the details of the careful planning typical of an audit sample acceptable for regulatory decisions. AIU says the sampling procedures were described as being based on judgment, knowledge of Commission rules, and experience, but the specific planning steps and documentation of the rationale for sample design decision were not provided. AIU complains that there is no rationale given for the choice of a judgmental rather than a statistical sample, no description of steps taken to assess the representative nature of the judgmental sample, no description of decision rules used in the evaluation of sampled costs, or of any of the other aspects of sample planning.

AIU argues that by only reviewing invoices associated with specific projects above $500,000 in total costs, Staff effectively divides the population into two populations, and selects a sample from only one of these populations. In AIU's view, this is no longer sampling the population of total plant additions, but sampling a population with total costs above $500,000. AIU says the remainder of costs associated with total plant additions (those costs outside of this population) was not sampled and is a distinct population.

Staff errs, AIU argues, by applying the characteristics of the sample it reviewed to a population that Staff did not review. AIU says there are two main types of plant additions: (1) Specific Projects – those projects whose total costs are above $100,000 and are related to a specific work order; and (2) Blanket Projects – reoccurring purchases or those projects whose total costs are below $100,000. Staff, AIU avers, did not review any invoices for specific projects whose total are less than $500,000, nor did Staff review any blanket projects. AIU argues that there is no reason to believe that the percentage of invoices associated with specific projects that Staff reviewed is representative of the percentage of invoices in all plant additions. AIU says, for instance, blanket projects include reoccurring purchases and installation costs of certain equipment, such as transformers. This population of costs, AIU suggests, may not include invoices, but rather receipts or other forms of recording an exchange, whereas specific projects are more often partially comprised of invoices.

Staff's rebuttal testimony, AIU claims, does not provide any evidence that the alleged substantiation error rate found in projects larger than $500,000 would be the same as the error rate in the smaller projects. According to AIU, Staff provides the unsupported statement that larger projects would be expected to have better documentation than smaller projects so, by inference, the alleged error rate would be a conservative estimate for the smaller projects. In fact, AIU says there are situations with carefully designed, unbiased statistical samples, in which Dr. Batcher has seen instances where larger projects or expenditures had higher error rates.

Staff's inclusion of electronic transactions as a portion of unsupported invoices, AIU asserts, is also improper. AIU says Staff's review is limited to invoices and does not include a review of supporting documentation related to electronic transactions. AIU believes it is unreasonable to determine a category of costs is fully unsupported simply because Staff fails to review support for that category of costs. AIU argues that this is synonymous to an auditor failing to review current inventory and concluding that such an inventory does not and has never existed.

According to AIU, Ms. Everson's statement that AIU offered no other sample is incorrect. AIU says that Mr. Taylor's rebuttal testimony and that of Dr. Batcher provides explanations of the proper population for which the sample's characteristics should be applied. AIU adds that Ameren Ex. 19.12 is a review of Staff's adjustment with the inclusion of all general ledger line items that Staff challenged. Within these exhibits, AIU claims it applied the review of these challenges to the proper population, calculated the amount still unsupported after review, and applied this percentage to the population from which the sample is derived. AIU asserts that this analysis is based on Staff's chosen sample, but provides a more complete and rigorous analysis of the sample and applies the sample's characteristics to the proper population.

AIU states that Mr. Taylor quantified the effect of Staff's improper application of its sample to total plant additions. AIU says Staff samples $35,446,676 out of $64,367,442, the population of projects with total costs over $500,000. AIU adds that the population that Staff does not sample from, those projects with total costs under $500,000 and blanket projects, totaled $547,845,558. AIU argues that incorrectly applying the sample's characteristics to the total plant additions results in a proposed disallowance of $124,622,861. AIU further argues that correctly applying the sample's characteristics to the population from which the sample is derived results in a proposed disallowance of $13,614,957. According to AIU, Staff's incorrect evaluation of the sample results in an overstatement of the proposed disallowance totaling $111,007,904.

AIU states that although Ms. Everson employs other audit methods that she could have used to validate and support capital additions as a whole, she errs by relying exclusively on her sample without also taking into consideration the results of her other audit reviews. AIU contends that Ms. Everson could have used continuing property records and property unit retirement records to review the AIU's plant additions;

however, a review of those records is not discussed anywhere in Ms. Everson's testimony.

Ms. Everson's analysis, AIU claims, is at odds with work done by other Staff witnesses in this case. AIU says Mr. Rockrohr samples the ten largest projects for each utility, and found issues with only two of those projects. One project related to plant held for future use, the other to a security system at an AmerenCIPS facility. AIU says the reasons for recommended disallowance of these projects relates to whether the investments were prudently incurred, not whether the project costs were sufficiently documented. According to AIU, Mr. Rockrohr's recommendation of only two disallowances is in contrast to Ms. Everson's conclusions in her direct testimony. AIU asserts that since Ms. Everson's approach applies to the entire universe of additions, she in effect is disallowing a second time some of the same capital additions dollars Mr. Rockrohr has proposed to disallow.

Ms. Everson's failure to take acquisitions, timing, and changes in accounting systems into account, AIU avers, leads to misleading and unfair results. AIU states that for AmerenCILCO's electric operations, 100% of the transactions reviewed occurred prior to 2005, prior to the acquisition of CILCO by Ameren. AIU adds that these projects were not transferred from Construction Work in Progress ("CWIP") to Utility Plant In Service until after 2004, and therefore are included in Ms. Everson's sample. AIU complains that Ms. Everson's sample results, however, were applied to 100% of all 2005 and 2006 capital additions placed in Utility Plant in Service. Since Ms. Everson has not considered how timing of transactions impacts her weighted disallowance calculations, AIU asserts that the application is flawed. AIU claims a more correct approach would attempt to differentiate the timing of transactions that give rise to 2005 to 2006 capital additions in a case such as this, where different accounting and invoice storage systems were employed with different owners, and the resulting application was applied to capital additions that for the most part, would have occurred after the transition periods. AIU says it is possible that pre-2005 transactions may be representative of post 2005 transactions, but Ms. Everson has not made that determination.

According to AIU, disallowing electronic transactions skews the percentage calculation of unsupported additions. AIU says all electronic transactions at issue occurred prior to October 2004 (acquisition of IP by Ameren) and yet the results were included in Ms. Everson's unsupported percentage for all additions. AIU says Ms. Everson's disallowance included 100% of all electronic transactions included within her sampled electric and gas projects. For gas projects, AIU indicates that those transactions totaled $2,286,148.32. AIU says Ms. Everson's unsupported percentage, with electronic transactions, is 51.74%. When this percent is applied to $118,215,000.00 of 2003-2006 capital additions, the resulting disallowance is $61,167,000.00 of capital additions. According to AIU, if Ms. Everson had adopted the same approach used by Staff in the prior IP electric rate case and excluded electronic transactions from her sample, the unsupported percentage would have changed to 9.62% from 51.74%, and resulted in a disallowance of $11,372,000.00. AIU asserts

that Ms. Everson's inclusion of $2.286 million of electronic transactions in the denominator of her unsupported calculation resulted in a proposed disallowance of $50 million in capital additions. AIU also asserts that the application of Ms. Everson's unsupported percentage to any Commission authorized 2004 AmerenIP gas capital additions approved in Docket No. 04-0476 is a form of retroactive ratemaking, because the Commission has already approved inclusion of such additions in rates.

AIU believes Ms. Everson's exclusion of electronic transactions supporting AmerenIP expenditures is unfounded for other reasons as well. AIU states that Ameren Ex. 19.13 provides the detailed electronic transaction disallowed by Staff in its calculation of the disallowance for AmerenIP electric and gas plant additions since the last rate case. AIU contends that IP's electronic records are reliable and accurate representations of its costs. AIU says it explained in detail the process for creating and approving the invoices and how the invoices tie into the accounts payable system and that in the prior rate case, Staff did not propose to disallow any electronic transaction data.

AIU says that Ameren Ex. 61.1 contains its response and supplemental response to Staff Data Request 14.03, in which Staff requested the vendor invoices to support the amounts shown on Ameren Ex. 19.13 for plant additions. AIU asserts that Ameren Ex. 61.1 explains that, with respect to IP, vendor payment support for Ameren Ex. 19.13 is available in electronic format due to the electronic Contractor Invoicing system used by IP. AIU says that although information summarizing the electronic invoice records is already provided in Ameren Ex. 19.13, additional electronic information associated with vendor payments is available if desired. Thus, in response to Ms. Everson's concern in rebuttal that no actual invoices have been provided to support IP's plant additions, AIU claims Ameren Ex. 61.1 contains paper printouts of contractor invoice records that were electronically created and stored in IP's Contractor Invoicing system. AIU states that each electronic invoice contained in Ameren Ex. 61.1 shows all of the information necessary to substantiate project costs for specific plant additions for IP, such as contractor name, descriptions of the work, work order numbers, and the person approving the invoice for payment.

The methodology employed by Ms. Everson in this case, AIU asserts, is not consistent with Staff's approach in prior cases. AIU claims that while it is not suggesting that Staff is required to audit plant additions the same way in every case, the fact that the audit was performed differently in this case than in other cases demonstrates that other audit techniques were available to supplement Staff's review of plant additions in this case.

In Docket No. 07-0566 for ComEd, AIU asserts that Staff witness Griffin raised a number of issues with regard to ComEd capitalization policies and capital additions, and discussed changes to the ComEd Property Unit Catalog. AIU says Mr. Griffin did not propose a calculation of an unsupported percentage similar to that presented by Ms. Everson. According to AIU, there is no evidence of a similar review undertaken or discussed by Mr. Griffin or any other Staff witness in that rate case. It appears to AIU

that Staff undertook no such sampling approach, and that Staff based its proposed capital additions adjustments entirely on other audit methods.

In recent cases involving other utilities, AIU avers that Staff has not required invoice-by-invoice support for plant additions. (AIU Initial Brief at 41, citing Docket Nos. 07-0241 and 07-0242 (Cons.) (Peoples Gas Light and Coke Company ("Peoples")/North Shore Gas Company ("North Shore")); Docket No. 04-0779 (Northern Illinois Gas Company ("Nicor")); Docket No. 05-0597 (ComEd); Docket No. 06-0285 (Aqua Illinois, Inc. ("Aqua")); and Docket No. 07-0357 (Mt. Carmel Public Utility Company)) In these cases, AIU asserts that Staff's approach was different than Ms. Everson's approach in this case. AIU believes that in other cases, Staff has not required this level of detail in conducting its review, and the Commission has not required this level of detail in approving other utilities' plant additions.

AIU contends that in Illinois-American Water Company ("IAWC") rate cases in Docket Nos. 90-0100, 92-0116, 95-0076, 97-0112, 00-0340, and 02-0690, Staff conducted an audit of capital additions, and one of the primary methods Staff relied on in those proceedings was a review of continuing property records, similar to that conducted by Ms. Everson in these proceedings. AIU says that in those cases where that audit method was employed, no further audit procedure was employed. According to AIU, Staff's approach in this case is not only flawed, it is an unwarranted departure from prior rate cases.

Ms. Everson, AIU states, admits that there may be valid reasons why certain invoice amounts do not match amounts on the list of projects that were provided. AIU claims that Ameren Exs. 19.12 and 43.6 demonstrate that there are valid explanations for many of the perceived discrepancies between the invoices and the listing, which casts doubt on Ms. Everson's proposed adjustment. AIU states that certain invoices differed by 1% from the amount presented in the project listing provided to Staff due to a discount extended by the vendor. AIU claims that the evidence it submitted in rebuttal supported the underlying cost directly in response to Ms. Everson's preferred audit approach of reviewing invoices. Where invoices could not be located or another reason was identified but could not be explained within the rebuttal filing deadline, AIU asserts that such costs are supported through other audit approaches, including support provided by the underlying general ledger queries, other project requirements, and continuing property records. According to AIU, Staff has not disputed that any of the underlying costs proposed for disallowance on Ms. Everson's Schedule 2.03 were either not incurred or should otherwise be ineligible for recovery, if the specific reason cited by Staff could be adequately addressed. AIU believes that any adjustments beyond those AIU conceded in rebuttal or in surrebuttal are inappropriate.

AIU states that with respect to Ms. Everson's first six criteria, Ameren Ex. 19.12, Schedules 1 through 6, Ms. Everson lists each invoice disallowed, based on a process of elimination, and a "best guess" as to the reason for the disallowance. According to AIU, Ameren Ex. 19.12, Schedules 1 through 6 also explain why the disallowance is not appropriate to the extent the explanation is unique or specific to that particular invoice.

AIU adds that Ameren Ex. 43.6, submitted in surrebuttal, updated Ameren Ex. 19.12 and provided more support. For some invoices, AIU says none of the reasons seemed to apply. In those cases, AIU indicated "No Reason" because the invoice was tied to the listing and none of the six criteria could be applied as a rationale for a disallowance. AIU states that there are some instances where AIU either could not locate an invoice or amounts did not match with the list relied on by Ms. Everson. While there are other ways to substantiate these costs, and some of the missing documents can directly be attributed to ownership transaction, AIU says it accepted, for purposes of this rate proceeding, an adjustment to rate base and depreciation expenses. AIU indicates that Ameren Ex. 19.12, Schedules 1 through 6 include a corrected calculation of Staff's Schedule 2.03 to consider evidence presented in rebuttal and an application of the unsupported percentage to the correct population, as discussed in the rebuttal testimonies of Mr. Taylor and Dr. Batcher.

AIU claims that Staff fails to adequately explain why Ms. Everson could not have used other audit methods to verify plant additions where an invoice was lacking. According to AIU, an invoice is one form of evidence that can be used to support plant addition amounts on the general ledger, but it is not the Holy Grail. In AIU's view, invoices are not the only appropriate, or even the best, evidence of plant addition costs. (AIU Reply Brief at 14, citing, Preston Utilities Corporation v. ICC, 39 Ill. 2d 457, 460 (1968) (upholding a Commission finding based on the premise that "the best evidence" of plant costs are "the general ledger, journal entries, and income tax returns")) AIU says it provided additional supporting documentation in the form of continuing property records, property/retirement unit catalogs, accounts payable records, the contractor system, and vendors' verifications. According to AIU, Staff's position is that none of this is a substitute for an invoice. AIU says, according to Staff, if there is no invoice for a project then the costs can not be supported. According to AIU, Staff has, in other cases, relied exclusively on continuing property records, property retirement catalogs, and other forms of non-invoice support to justify plant additions.

AIU alleges that Ms. Everson's rebuttal testimony does not respond to a large portion of Mr. Stafford's rebuttal testimony. AIU asserts that the vast majority of the invoices detail explanations Mr. Stafford provided in rebuttal, with the exception of a few specific examples. AIU claims Ms. Everson does not address why she continues to disallow costs where the exact amount of the cost was highlighted on the invoice. AIU contends there are at least 265 invoices totaling about $1.7 million, with no explanation as to why these costs remain unsupported.

AIU argues that Staff's failure to review information provided to support plant additions cast serious doubt on the validity of Ms. Everson's adjustment. AIU asserts that before Ms. Everson filed her rebuttal testimony, AIU supplemented its responses to Ms. Everson's Data Requests MHE 3.03 and 3.06. AIU claims its supplemental responses modified the amount attributable to electronic transactions. AIU says Ms. Everson refused to incorporate this supplemental information into her analysis.

AIU claims to have been and currently be in compliance with the Commission's document retention requirements. AIU asserts that it has appropriate document systems and controls in place, and has made significant enhancements to its systems and controls. AIU says that Ameren Ex. 52.1 is a detailed description of its project file maintenance procedures. According to AIU, these procedures indicate that it has a proper system for retaining documents in place.

Even if the Commission were to find that AIU is or was not in compliance with Commission rules, taking into consideration that the data and records at issue are largely pre-acquisition, AIU believes this finding would not justify permanent disallowance. Permanent disallowance, AIU argues, is the rate case equivalent of the death penalty. Where rate base items are permanently disallowed, AIU says the utility may never earn a return on or of those items. Permanent disallowance, AIU claims, is therefore reserved for imprudent expenditures. AIU says its research reveals no precedent for permanent disallowance of prudent expenditures based on allegedly deficient documentation. No party to this proceeding, AIU adds, has alleged that any amounts included in Ms. Everson's adjustment represent imprudent expenditures. According to AIU, Staff has offered no support for its assertion that a permanent disallowance can be ordered based on documentation concerns. Because there is no issue in this proceeding concerning the prudence of any expenditures for plant additions, AIU maintains there is no basis in law or fact to permanently disallow rate base recovery of any such additions.

If the Commission feels that AIU has not adequately supported plant additions, AIU says it is prepared to suffer the consequences. While it would be one thing to disallow plant additions in this case, AIU asserts that to permanently disallow any plant additions is entirely different. AIU says it would be forever precluded from earning a return on or of property used and useful in providing service. AIU expresses concern that it would send a message that AIU loses not only in this case, but in all future cases. If any plant additions are disallowed in this case, AIU argues that those additions under the law must be included in rate base in the next case, provided they are adequately supported at that time. (AIU Initial Brief at 47, citing Illinois Power Co., Docket No. 89-0276, Order at 315 (1990))

AIU states that Staff cites no case law or Commission decision to support a permanent disallowance. AIU says it does not dispute that CILCO and IP were public utilities and subject to the Commission's record retention rules. According to AIU, left unsaid by Staff is what current AIU management was supposed to do to ensure that CILCO and IP properly maintained records before Ameren acquired those entities. AIU states that to the extent any violations occurred prior to Ameren's acquisitions, they were committed by the prior owners.

In AIU's view, Staff's recommendation for a fine should also be rejected. AIU claims Staff has ignored evidence provided by AIU that responds to many of Staff's concerns regarding plant records. AIU asserts that most of the difficulties in locating records arose from the fact that two of the utilities were previously under different

ownership. While it may be true that these companies had record keeping obligations before being acquired by Ameren, AIU claims it is equally true that Ameren had absolutely nothing to do with these companies' recordkeeping practices until it acquired the companies. AIU says that Ameren acquired AmerenCILCO in early 2003 and AmerenIP at the end of 2004. While this proceeding deals with projects that went into service by the end of a 2006 test year, AIU asserts that many of those projects included costs, and related invoices, that predated Ameren's acquisitions.

In addition to AIU's lack of control over prior record preservation, AIU says there were also transitional issues, such as IP's use of a particular electronic document system that was taken out of service when AmerenIP was integrated into the Ameren system. With respect to AmerenCILCO, before the acquisition by Ameren, AIU claims there were two different systems in place. Prior to the acquisition of CILCO by AES in late 1998, AIU says invoices were centrally processed by a corporate Accounts Payable department. This is consistent with the system utilized by AIU. Starting in 1999 under AES' ownership, in addition to a small centralized accounts payable group that processed electronic payments and miscellaneous invoices, AIU says decentralized accounts payable processes were set up at the Duck Creek, Edwards, Springfield, Persimmon Gas, and Pioneer Park Electric areas. AIU states that each area received its own invoices and had separate checking accounts to pay vendors. AIU adds that all five areas were also responsible for bank reconciliations as well as retaining and storing their checks, bank statements, and invoices. According to AIU, the invoices at Pioneer Park Electric were housed in boxes in the storeroom and erroneously discarded after the acquisition by Ameren. AIU indicates it is not aware of any systemic loss of AmerenCILCO invoices other than those destroyed at Pioneer Park Electric. AIU states that for AmerenCILCO, 100% of the transactions sampled by Ms. Everson occurred prior to the acquisition of CILCO by Ameren.

Although AIU believes the Commission should reject the recommendations for fines and permanent disallowance, AIU says it has no objection to a requirement that it subject its document processing and retention for plant additions and retirements to an internal audit. AIU says that Ameren's internal audit department already reviews these matters annually, and works with its outside auditors to review document processing and retention. AIU indicates that Ameren Ex. 52.2 is a detailed outline of the most recent review. In addition, AIU says that it has already asked internal audit to review the issues surrounding the CILCO pre-acquisition document loss and make any appropriate recommendations.

AIU further claims that Staff's call for penalties fails to recognize that AIU is already being penalized. AIU states that all of the assets have already been in service since 2006 or earlier, and it will not earn a return on such assets until at least October 2008. In light of this fact, AIU contends that permanent disallowance and/or fines would be excessive, confiscatory, and unwarranted. In response to Staff's claims that there is no reason to believe that at some time in the future AIU will be more able to locate and produce support for these additions, AIU suggests that Staff review the information

already provided in Ameren Exs. 19.12 and 43.6. AIU insists that the information supporting plant additions is available today.

In response to Staff's suggestion that permanent disallowance is warranted to provide AIU with the incentive to adequately support plant additions and to make AIU accept responsibility, AIU says it has done nothing wrong. AIU suggests that to the extent the Commission believes otherwise, the remedy is to disallow certain plant additions in this case. AIU claims it would have an incentive to document plant additions in a manner acceptable to the Commission in the next case in order to recover the costs of those additions. AIU maintains that if it provides support for these additions in the next case, it is legally entitled to recover the costs, regardless of the outcome in this case.

In response to Staff's assertion that AIU's records are in remarkably poor condition, AIU alleges that Ms. Everson is in no position to make such a claim. AIU says she did not perform her review at AIU's offices and does not otherwise have any basis to pass judgment on how AIU keep its records. AIU states that her assessment is based solely on what AIU provided to her during discovery in this proceeding. According to AIU, Staff is free to criticize the format in which information was provided in discovery, but there is no record support for the statement that the manner in which information was produced in discovery is reflective of how records are compiled and maintained at AIU's offices.

In AIU's view, Staff overplays the effort needed to review the information provided by AIU. The volume of information involved, AIU claims, is a direct reflection of the scope of Staff's adjustment. According to AIU, whether Staff has thoroughly reviewed it or not, this evidence should not be ignored.

AIU contends that Staff attempts to reverse the burden of proof. In AIU's view, Staff's arguments and position in this case seem to ignore the fact that invoices offer additional support for general ledger amounts – not the other way around. AIU says its books are regulated, and audited, and are evidence in and of themselves of AIU's costs. According to AIU, Staff has ignored the significance of AIU's audited records, the controls that are in place, and the existence of the plant additions themselves. AIU complains that Staff's proposed adjustments would effectively disallow from rate base approximately $150 million in plant additions while AIU believes the correct adjustment is approximately $25.6 million.

AIU disputes Staff's claim that providing Ex. 19.12 during rebuttal constitutes a deliberate attempt to withhold information. AIU asserts that this information was provided in direct response to Staff's direct testimony recommending the disallowances. AIU says it had no motive to withhold information that supports plant additions. AIU argues that considering the experience in prior cases, AIU had every reason to be as above-board with Staff as possible in this case.

In response to Staff's complaints about receiving information after Staff's rebuttal, AIU claims that is the point of surrebuttal. In AIU's view, there is nothing improper about providing surrebuttal evidence that is responsive to Staff's rebuttal testimony. AIU says the surrebuttal evidence was put forth specifically to rebut the positions taken by Staff in its rebuttal.

Staff suggests that its original proposed adjustments should be adopted unless the decision maker conducts an analysis of the information provided in Ameren's surrebuttal testimony. AIU says it agrees that the Commission should analyze its surrebuttal evidence. According to AIU, the fact that it may be time consuming and meticulous to review the data is not a reason to ignore it. AIU claims it would not be nearly as time consuming and meticulous to review AIU's evidence as Staff would like the Commission to believe.

AIU says with regard to Ameren Ex. 43.6, Staff basically suggests that the information in this exhibit should be ignored because it is too hard to figure out. AIU agrees that this exhibit is hard to figure out if reviewed in the manner that Staff suggests and as described in Staff's Initial Brief. AIU states that Ex. 43.6 updates, corrects, and supplements Ameren Ex. 19.12. AIU alleges that Staff's apparent objective is not to determine whether Ex. 43.6 supports the requested level of plant additions, but whether the information provided as new information in surrebuttal was not in fact duplicative of earlier productions. AIU claims that Staff spent an afternoon cross-examining Mr. Stafford about discrepancies as low as $2.55 and $2.32. According to AIU, approximately 98% of the evidence was in Staff's hands after AIU submitted its rebuttal testimony. AIU asserts that even if Ameren Ex. 43.6 is not considered, Ameren Ex. 19.12 largely stands on its own in support of the requested level of plant additions.

Staff argues that the Commission should disregard the vendor supplied invoices contained in Ameren Ex. 42.2. First, AIU says Staff argues that some of the invoices contain amounts that do not agree with the summary listing. AIU claims that AIU witness Nelson explains why the amounts are different. Second, AIU says Staff complains that the affidavits are hearsay. AIU responds that they are part of the record. Third, AIU says Staff does not like how some of the invoices are worded. AIU asserts that regardless of how they are worded, the affidavits support the amount of AIU's plant additions.

According to AIU, Staff also attempts to create an issue from the fact that certain invoices were mistakenly billed to the wrong AIU entity by contractors. AIU suggests that the Commission understands that each of the utilities is a separate legal entity with separate books and records. AIU claims the significance of this legal separation is not always apparent to contractors that perform work for AIU. AIU states that its project managers make sure that invoices are assigned to the proper utility and project. In AIU's view, that this explanation is not apparent from the face of an actual invoice is of no import. That, AIU argues, is the reason why the project manager follows up to make sure the proper company is charged.

AIU understands Staff's position to be that if Staff could not read an invoice, the amount supported is $0. AIU suggests that Staff could have advised it that there were certain invoices that were illegible, but Staff never did so. AIU claims that had Ms. Everson promptly made known that she could not read some of the invoices, AIU would have quickly provided better copies. AIU says when this issue was made known to it, Mr. Stafford provided legible copies.

AIU states that where invoices did not match the summary listings, Staff proposes to disallow the entire invoice amount. AIU maintains that there could be legitimate reasons for the differences. This being the case, AIU believes it is not unreasonable to expect Staff to make some effort to determine whether such a legitimate reason exists. AIU suggests a good place to start would be to identify to AIU which invoice amounts do not match the summary listing. AIU says Staff never did so, claiming it has no obligation to further expend its limited resources to help AIU satisfy its burden of proof. AIU insists that Staff has the burden to produce evidence to support its adjustments. AIU says it provided responsive evidence that proves, despite differences between invoice amounts and amounts on the summary listing, the reasonableness of the addition.

AIU also claims that many of the differences are a few dollars. AIU states that Voucher #003347 associated with AmerenCIPS project 16895 is an invoice for $391.08. AIU believes that Ms. Everson disallowed this invoice because the amount presented on the summary was $387.17. AIU claims the difference is attributable to a 1% discount for early payment.

In response to Staff's assertion that AIU never provided evidence to substantiate its purchasing rate policy, AIU claims it produced detailed schedules identifying each discrepancy attributable to a purchasing rate. (Ameren Exs. 19.12 and 43.6) In addition, AIU says it responded to Staff Data Request 12.05 by providing a copy of AmerenCIPS purchasing rate policy in effect during June 2004. AIU complains that Staff did not issue any further Data Requests to better understand how AIU's purchasing rates worked. AIU further complains that unlike the prior rate case, in which Staff had discussions with AIU regarding purchase rates to obtain a better understanding of how such rates worked, Staff made no such effort to understand purchase rates in this case.

With regard to invoices that included finance charges, AIU complains that Staff attempts to make a mountain out of a mole hill. AIU says there is no list of which invoices included finance charges. Ms. Everson agrees that it is reasonable to ensure that an invoice amount is appropriate before paying the invoice. AIU states that if being reasonable ultimately results in the imposition of finance charges, so be it. AIU notes that where invoice amounts differed because of the application of a discount for early payment, Ms. Everson excluded the entire invoice because of the perceived discrepancy.

AIU asserts that it learned for the first time, through Staff's Initial Brief, that employee meals are another category of expense items that Staff disallowed. According to AIU, Staff relies on the fact that, while on the stand, Mr. Stafford could not cite a definitive reference from the Uniform System of Accounts ("USOA") indicating that employee meals may be capitalized as part of plant additions. According to AIU, the USOA does support the capitalization of employee meals. Specifically, Electric Plant Instruction 3, under "Components of Construction Costs," establishes that "Labor includes the pay and expenses of employees of the utility engaged on construction work." (18 CFR § 101 (emphasis added); 83 Ill. Admin 415.430.)

AIU says Staff's position on electronic transfers is based on its review of Ameren Ex. 19.13, which provides in spreadsheet form a description of electronic transactions. AIU states that contrary to Staff's assertion that this information came from the general ledger, Ex. 19.13 came from a separate system that contains information above and beyond the information contained in the general ledger. AIU complains that Staff fails to mention that AIU witness Livasy submits Ameren Ex. 61.1, which provides printed copies of invoice records maintained in AmerenIP's electronic transaction records. AIU says it is true that AIU believed that these records could not be retrieved from a legacy system; however, the records have since been retrieved. AIU claims the records should not be ignored. AIU further claims that all of the information necessary to support the electronic transactions, which total approximately $1.5 million, is contained in Ameren Ex. 61.1.

With respect to the 2004 IP gas historical plant additions, Staff claims that despite the fact that IP was allowed a certain level of 2004 pro forma plant additions in the last rate case, it is appropriate to disallow 2004 plant additions in this case. AIU believes Staff's arguments are misguided because some of the costs approved by the Commission in the prior case were actuals, not estimates. AIU claims Schedule 14.03 IP G shows $33.522 million of additions used in Staff's calculation of its unsupported percentage. AIU states that a review of IP Ex. 12.4 in Docket No. 04-0476 shows that over $25 million was in service at time of review and, therefore, not an estimate. AIU also asserts that $16.982 million of Completed CWIP Not Transferred to Plant in Service were also actuals, not estimates. AIU says these amounts combined exceed the $33.522 million of additions Staff used in its calculation.

b. Staff's Position

Ms. Everson reviewed AIU's 2003 through 2006 plant additions which it seeks to include in rate base. The objective of such a review, Staff says, is to establish whether the underlying costs for such plant additions are adequately supported by documented evidence. Staff believes that the required support for these plant additions were either deficient in many respects or non-existent. Staff developed a sample of projects for each of the six utilities that were based on Ms. Everson's professional judgment, knowledge, and experience as an accountant. Specifically, for each of the six utilities, she reviewed and analyzed the invoices and the summary listings that were associated with projects having a total dollar value greater than $500,000. Ms. Everson made the

assumption that more care and documentation would be given to projects with a larger cost than those with smaller costs; thus, better records would be available to support the larger projects. For each of the six utilities, Ms. Everson developed a sample for which she determined the percentage of unsupported project costs to the total costs of the projects within the sample. The resulting company-specific percentage of unsupported costs was then applied to the total 2003-2006 plant additions for the respective utility to determine the amount of Staff's proposed plant disallowance.

Staff says its review of over 8,700 pages of project invoices and listings that summarized the amounts of such invoices recorded by AIU (referred to by Staff as "summary listings") resulted in the discovery of numerous problems. According to Staff, adequate support for the plant costs was non-existent or had one or more of the following deficiencies: 1) duplicate invoices, 2) billings to the wrong company, 3) invoices not found that correspond to the listing of invoices provided, 4) amounts on invoices that did not correspond to the listing, 5) project not determinable from the invoice or the invoice is not related to the project, 6) illegible invoices, and 7) certain AmerenIP project amounts that were paid via electronic transfer without a supporting invoice.

According to Staff, the company-specific percentages of unsupported plant costs are as follows: AmerenCILCO gas: 11.58% electric: 35.45%; AmerenCIPS gas: 25.56% electric: 2.35%; AmerenIP gas: 51.74% electric: 12.78%. Staff states that when these percentages are applied to the respective totals for plant additions from 2003 through 2006, these percentages result in the following proposed plant disallowances: AmerenCILCO gas: $6,563,000 electric: $30,005,000; AmerenCIPS gas: $1,736,000 electric: $2,347,000; AmerenIP gas: $49,810,000 electric: $34,135,000.

According to Staff, AIU's failure to properly document plant additions has a long and contentious history. Staff states that in Docket No. 99-0121, the Commission Order demonstrates CILCO's inadequate support for its pro forma plant adjustments and the untimely production of such information to Staff. Unlike in the current docket, however, Staff says CILCO accepted responsibility in that rate case for its failure to provide the appropriate documentation for its plant requests and recognized it should bear any hardship for failing to provide such documentation. (Staff Initial Brief at 10-11, citing Docket No. 99-0121, Order at 22-27 and 29-30)

Staff claims that in its last electric delivery services rate cases, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), AIU again failed to provide sufficient documentation to support its plant costs. Staff states that in those consolidated dockets, the Commission imposed a plant disallowance due to AIU's failure to support its plant additions. (Staff Initial Brief at 11-12, citing Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 13 and 7) Staff says its proposed disallowances in that case were related solely to disputes over documentation of AIU's reasonably incurred costs.

Staff asserts that in the current proceeding, the same pattern from prior rate cases repeats itself. Staff says that in the MHE 3 series of data requests (Staff Data

Requests MHE 3.01-3.06) Staff requested copies of invoices, a listing of invoices, and all loading factors for the projects chosen for the sample for each of the six utilities. AIU provided six compact discs ("CDs") in response during December 2007 through February 19, 2008. Staff indicates that the CDs contained approximately 8,700 pages of documentation, including the summary listings and copies of invoices. Staff adds that the response on February 5, 2008, dismissed the request for all loading factors as being ". . . unduly burdensome and unreasonably time consuming . . . . Further, the information is not relevant, nor material, nor likely to lead to the discovery of admissible evidence." (Staff Initial Brief at 12-13, citing Staff Ex. 14.0R, Att. A) Staff says it understood this to be the entirety of support that AIU could provide for the sample of plant additions. The information in the six CDs and the narrative response to the MHE 3 series formed the basis for Staff's analysis and recommendation.

Staff claims that AIU's initial productions in discovery did not contain all of the requested documentation, nor, in Staff's view, did it contain sufficient documentation for the plant costs it seeks to recover from ratepayers. Staff complains that AIU provided additional information in its rebuttal testimony that should have been provided earlier in the case when such information was requested by Staff. Staff says Ameren Ex. 19.12 includes a detailed listing that attempts to provide a reason why AIU considered disallowed amounts as supported. For some line items on Ameren Ex. 19.12, Staff says AIU indicates: "[c]an't locate the invoice." (Staff Initial Brief at 13, citing Ameren Ex. 19.12, Sch. 1-CILCO-E, at 10-12.) Staff adds that Ameren Ex. 19.12 also includes Schedules 8-13, provided on a CD which contained 83 separate pdf files, containing invoices and supporting documentation as requested in the MHE 3 series of data requests, named by schedule and part. In Staff's view, the provision of this volume of information without a clear organizational framework at the rebuttal stage of the proceeding made it impossible for Staff to complete a thorough review.

Staff says it reviewed a sampling of the information provided in Ameren Ex. 19.12 and sent data requests to AIU. Staff claims the data requests sought information regarding the explanations provided in Ex. 19.12 to attempt to determine if the explanations were indeed the reasons why the invoice amounts and AIU's summary listings did not match. Staff asserts that AIU's data request responses were vague and in some instances contradicted Ex. 19.12, and failed to fully reconcile the differences between the invoice amounts and the amounts shown on the summary listings. One of the reasons provided with Ameren Ex. 19.12 for the mismatch between the summary listings and the invoices, Staff states, were "purchase adders." Staff claims that AIU never provided any information as to what the appropriate purchase adder was for AmerenCILCO and AmerenIP. According to Staff, AIU provided no indication of what the fixed rate charge was or when it would be applied.

Staff argues that by providing information in rebuttal testimony rather than in responses to discovery, AIU has deliberately attempted to withhold information to support its request for recovery of plant additions in an adequate and timely manner. Such litigation strategy, Staff contends, is a common theme in the prior AIU cases.

Staff believes the Commission has given AIU more than enough warnings and must hold AIU accountable for the consequences of its actions.

Staff states that when it requested a separate identification of the type and amount of all loading factors in connection with its review of plant additions, AIU protested that this would require an examination of each invoice. Staff says it accepted AIU's explanation that this would be unduly burdensome and time consuming. Staff, however, claims that it could not accept invoices as support for a different level of costs than was reflected on the invoice. According to Staff, AIU claims it provided Staff with the information necessary to complete a review of plant additions; however, Staff says AIU did not provide it with sufficient information to support all of the plant additions that AIU proposed be included in rate base. Staff argues that it does not know what documentation AIU possesses or the level of burden of producing the documentation. According to Staff, AIU knows what documentation it possesses, the difficulty of producing it, and the consequences of failing to produce support for its plant additions.

Staff asserts that AIU is aware that unsupported plant additions will not be included in rate base, and is aware of the importance of locating and producing support for plant additions. Staff contends that if AIU deems support to be overly burdensome to provide, Staff can complete its analysis without the additional documentation but, since costs can not be included in rate base unless they are supported, the failure to provide support will inevitably result in adjustments. According to Staff, AIU's provision of breakouts of the costs associated with each project in response to Staff data requests MHE 3.01-3.06 was an ineffective substitute for providing the loading factors. Staff states that gross loading factors were provided, not specific amounts for individual line items for which there were differences between the line item on the summary listing and any invoice. In Staff's view, it was not clear how much of the gross amounts in the breakouts related to such items and how much related to items for which no supporting document was provided.

Staff also argues that compliance with initial filing requirements does not equate to bearing the burden to prove plant additions. Neither, Staff says, does supplying additional information in response to Staff Data Requests and in rebuttal and surrebuttal testimonies necessarily prove the plant additions. According to Staff, it is not the quantity of documents produced or the timing of when the documents are produced that determines whether AIU has met its burden of proof. Staff states that the plant additions for which AIU provided invoice-by-invoice support were allowed by Staff.

According to Staff, AIU is apparently claiming that it has made a showing of the costs necessary to provide service by providing the minimum filing requirements and what amounts to a mountain of paper. Staff states that Part 285 simply provides the minimum filing requirements. Staff argues that providing large quantities of documents that can not be reconciled to the general ledger is not sufficient to satisfy AIU's burden of proof under Section 9-201(c) of the Act. Staff claims the documents AIU provided to support plant additions were replete with deficiencies.

In Staff's view, AIU's reliance on City of Chicago for the premise that it need only make a "showing" of the costs necessary to provide service is misplaced. Staff states that AIU is proposing to include plant additions, for which it failed to provide support, in rate base. Staff argues that absent external support, AIU has not shown by a preponderance of the evidence that plant additions are reasonable. Staff also refutes AIU's reliance on Docket Nos. 83-0537/84-0555 (Order at 183-184). Staff insists there is no presumption of reasonableness.

Staff says AIU argues that the basis for Staff's plant additions adjustment is only because of issues pertaining to the documentation of expenditures. AIU, Staff adds, distinguishes this adjustment from one based on a cost being imprudent or unreasonable. Staff calls this hair splitting. Staff repeats that utilities are required to retain records and to support costs for a reason.

Staff asserts that AIU is in violation of 83 Ill Adm. Code 420, "The Preservation of Records of Electric Utilities" ("Part 420"), and 83 Ill. Adm. Code 510, "The Preservation of Records of Gas Utilities" ("Part 510"). Staff states that the rules require that the detail summary and distribution records supporting journal vouchers for plant accounts be retained for the seven years prior to the date as of which the original costs of plant have been unconditionally determined or approved by the Commission.

Staff says AIU attempted to excuse its failure to retain its records and to support its costs by pointing to different corporate ownership of CILCO and IP prior to their acquisition by Ameren. Staff says the implication of AIU's statement is that this somehow absolves it of its record preservation obligations. Staff states that each of the acquired AIU companies was a public utility company prior to Ameren's acquisition and AIU operated AmerenUE in Illinois prior to merging with the other public utility companies.

According to Staff, AIU complains that Staff refused to take into consideration the timing of the transactions and the changes in systems and corporate ownership when recommending a disallowance due to missing invoices or unsubstantiated amounts. Staff says AIU has made this claim in two prior rate cases, one as far back as 1999, and in each case, this excuse was rejected by the Commission. Staff argues that it is irrelevant that AIU had no control over the actions of the prior owners. Staff says that when AIU was seeking approval of its reorganizations, it committed to be subject to all of the rules and regulations and should be held to its commitment.

Staff adds that AIU failed to notify the Commission within 90 days of the destruction or loss of such records, as required by Section 420.70 of Part 420 and Section 510.70 of Part 510. Instead, Staff asserts that only after it raised this as an issue did AIU provide the required notice to the Commission that CILCO's September 2000 through December 2002 accounts payable vouchers were prematurely destroyed in September 2003. Staff states that this notice was provided to the Commission significantly beyond the 90 days required by Sections 420.70 and 510.70, and it does

not cover other documents that AIU has been unable to provide for AmerenCIPS and AmerenIP for which no explanation has been provided.

Staff states that although AIU witness Steinke admits that it must accept responsibility for its inability to produce plant cost documentation sought by Staff in this case, he also claims that AIU is in compliance with the Commission's requirements for preservation of records. According to Staff, AIU can not have it both ways: pretending to accept its responsibility for its failure to produce records and then claiming it is in compliance with the Commission's record retention policies.

Considerable resources, Staff contends, have been spent in this proceeding to provide, explain, and review AIU's support for plant addition costs since its last rate case. Staff maintains that AIU has failed to retain and produce records it is required by administrative rule to preserve. Staff adds that in some circumstances AIU relied upon third parties' records. Staff says that in other circumstances, AIU retracted previously supplied explanations for discrepancies in its documentation. Staff believes that AIU is unable to adequately explain all the discrepancies between its plant invoices and the summary listings. As a result, Staff contends that there is doubt as to whether any of the information provided on Ameren Ex. 19.12, or in exhibits attached to its surrebuttal testimony can be relied upon. Staff argues that there is no reason to believe that at some time in the future AIU will be more able to locate and produce support for these plant additions. Staff claims the support should have been generated at the time the plant was added and there would be no reason that the support was not available in 2008, but would be available in 2009 or 2010. Staff recommends that AIU permanently write-off all plant disallowance amounts ordered in this proceeding and be prohibited from seeking recovery of these amounts in any future rate proceeding. Staff believes a permanent disallowance will close the book on the matter allowing AIU and Staff to focus on more timely issues in the next rate case.

According to Staff, the only argument Mr. Steinke offers to rebut Staff's recommendation of a permanent disallowance is to state that such a disallowance is unduly harsh and would not be a positive event for AIU. Staff maintains this is not the first or second instance in which AIU was put on notice that it must fulfill its responsibility to support its request for recovery of plant costs with adequate and timely documentation. Staff asserts that AIU has failed to do so time and again and in a significant manner. Staff claims the magnitude of the apparent disarray in AIU's records has resulted in the Staff proposed disallowance. Staff maintains that there is no reason to believe that documents unavailable now will materialize before the next rate case.

To provide AIU with a clear incentive to fulfill its obligation of adequately supporting plant costs for which it seeks rate recovery, Staff urges the Commission to permanently disallow unsupported plant costs in this proceeding. Staff asserts that a permanent disallowance would make AIU truly accept its responsibility by accepting the consequences of its failure to retain and/or produce records. To do otherwise, Staff argues, would be tantamount to encouraging AIU to continue the same pattern it has followed over the years of providing inadequate information to support costs that it

seeks to have ratepayers pay. In addition, Staff asserts that failure to order a permanent disallowance would allow AIU, in the next rate case, to focus on producing documentation for the plant additions added subsequent to this proceeding.

According to Staff, if the Commission were to allow unsupported costs to remain in the AIU plant accounts, those same disallowed plant costs would be included in rate base in all future rate proceedings. Staff alleges that all future proposed revenue requirements would include a return on what it calls phantom plant and a recovery of the phantom plant through depreciation expense. Staff asserts that a permanent disallowance of the costs would remove the costs from the AIU plant accounts thus removing this possibility.

In its Reply Brief, Staff states that, generally, the plant in service balance should always be determined by beginning with the last original cost balance ordered by the Commission, adding properly supported plant additions and subtracting documented retirements. Staff asserts that to start with a number that includes plant additions that the Commission found to have deficient documentation in a previous case improperly ignores and overrides the previous Commission order.

Staff claims that the notion that the Commission has not ordered permanent disallowances for lack of documentation does not bear scrutiny. Staff says the Commission in four previous dockets made adjustments for unsupported plant additions due to poor or non-existent utility records. According to Staff, the effect of these orders is a permanent disallowance since the records were found to be non-existent or so deficient that the plant additions can not be substantiated at the time of the orders or in a subsequent proceeding.

Staff states that in Docket No. 04-0610, a rate proceeding of New Landing Utility, Inc., the Commission laid out how the plant-in-service balance is determined:

> Staff witness Griffin calculated utility plant by beginning with the allowed level of Utility Plant for ratemaking purposes found in the previous rate case. (See 79-0676/79-0675 (Cons.) at 11, 15 (Jan. 14. 1981)). Plant additions supported by documentation were added to the water and sewer rate bases. . . . Having reviewed the entire record in this proceeding, the Commission cannot accept the AG's proposal to utilize the Company's Annual Report as the basis for establishing rate base in this proceeding. It is clear that NLU's accounting procedures and records since the last rate case are flawed. Contrary to the AG's suggestion, the Commission simply cannot rely upon NLU's annual report and underlying accounting records to set rates in this proceeding. Thus, Staff's recommended approach to establishing rate base in this proceeding is adopted. (Order at 4-5)

In Docket Nos. 03-0398/03-0399/03-0400/03-0401/03-0402 (Cons.), a rate proceeding of Cedar Bluff Utilities, Inc., Apple Canyon Utility Company, Charmar Water Company, Cherry Hill Water Company, and Northern Hills Water and Sewer Company,

Staff says the Commission adjusted the current revenue requirement to reflect previous disallowances made by the Commission in the previous rate case. The order states:

> Staff proposed adjustments to reflect rulings in previous Commission Orders. (Staff Group Ex. 2.0). These adjustments reduce rate base for Apple Canyon and Charmar. These adjustments also incorporate adjustments that were never made from the Commission's order in Docket No. 90-0475/92-0401, which concerned Apple Canyon, and Charmar's short form filing with a test year ending December 31, 1989. The Companies did not contest the adjustments. (Order at 12)

Staff claims the order also lends support that the Commission expects plant additions to be supported by documentation as the language below indicates:

> Staff proposed adjustments to reduce the test year plant amount to reflect those additions and retirements that the Companies could not verify. (Staff Group Ex. 2.0). These adjustments decreased plant for Cedar Bluff, Apple Canyon and Charmar. Cedar Bluff's test year plant was reduced by the amount of additions and retirements, for which, it could not provide any supporting documentation. Both Apple Canyon's and Charmar's test year plant were reduced by the amounts of additions, for which the Companies could not provide any supporting documentation. Corresponding adjustments to accumulated depreciation, depreciation expense, and accumulated deferred income taxes were also made. The Companies did not contest any of these adjustments. (Order at 11)

In Docket No. 98-0045, a rate proceeding for Northern Hills Water Company, Staff claims the order refers to the company recording plant adjustments permanently on its books and records for adjustments from the prior rate case not reflected in the company's filing:

> The Company accepted Staff's recommended rate base adjustments as set forth on Appendix A, Schedule 4, and on Appendix C, Schedule 4. The Company agreed to record the plant adjustments permanently on its books and records when the transactions are complete. (Order at 4)

In Docket No. 98-0046, a rate proceeding for Del Mar Water Corporation, the Order states:

> The Company accepted Staff's recommended rate base adjustments as set forth on Appendix A, Schedule 4, and it agreed to record the plant adjustments permanently on its books and records when the transactions are complete. (Order at 3)

Staff believes a permanent disallowance would make it clear to AIU that it can not continue to promise to do better, but continue to fail to comply with Commission rules.

AIU witness Taylor claims that Ms. Everson's sampling methodology was flawed since the entire population of plant additions was not sampled. Staff states that Mr. Taylor conceded that it is not within the scope of his testimony to review the legitimacy of Staff's conclusions regarding plant additions. According to Staff, AIU witness Batcher criticized Ms. Everson's reliance upon a judgmental sample since unlike statistically based random samples, accuracy of judgmentally selected samples can not be assessed in a scientific or objective manner.

Staff states that in performing her plant additions analysis, Ms. Everson narrowed her review to projects $500,000 or more because she expected, based upon her professional experience, that these larger projects would have better documentation and cost support than would smaller projects. Staff argues that in limiting her sample to the larger projects, Ms. Everson's recommended adjustment to AIU's plant is conservatively low. In Staff's view, if Ms. Everson's analysis is to be faulted, it should be faulted for perhaps not recommending a greater disallowance.

Staff claims AIU has the burden of proof to show that the application of Ms. Everson's judgment and experience has led to an incorrect result. According to Staff, AIU did not provide any evidence to show that had Ms. Everson utilized a statistical sample, the resulting disallowances would be materially different than what has been recommended by Staff.

In its Reply Brief, Staff claims that AIU's position on statistical sampling and on extrapolating the result of an analysis on a sub-group of a population to the larger population that was not statistically sampled directly conflicts with its own method for analyzing the reasonableness of AMS costs allocated to AIU. Staff states that in his study of AMS services and costs, AIU witness Adams chose a sample of 197 service requests ("SRs") out of 881 SRs with allocation factors that affected AIU. Staff says he selected his sample by choosing SRs that had charges allocated to Administrative and General ("A&G") accounts and that totaled more than $50,000. Staff states that Mr. Adams used the results of his analysis of this judgmental sample from a sub-group of the population to assess the reasonableness of AMS' costs allocated to each of the Ameren subsidiaries. Staff says the basis for the $50,000 criterion was his professional judgment. According to Staff, Mr. Adams assumed that if the larger dollars are being charged and allocated in an appropriate manner, that everything under $50,000 was as well. Staff contends that this judgment is similar to Ms. Everson's reliance on her experience and judgment that the larger projects would have better documentation and cost support than would smaller projects. Staff argues that since AIU continues to assert that Mr. Adams' AMS analysis should be relied upon by the Commission, it can not dismiss Ms. Everson's plant additions analysis.

Staff states that while Ms. Everson prepared no written plan that does not mean that no plan was developed prior to her review of plant additions. Staff says it requested and received a listing of projects of $500,000 or more prior to selecting its sample or conducting its review. Staff claims its request for information regarding plant

additions projects with a total greater than $500,000 demonstrates that a plan existed to review plant additions projects with a total greater than $500,000. In addition, Ms. Everson indicated that she determined based on her experience at the Commission that it is reasonable to expect that more care in documentation is given to larger projects than to smaller ones; thus, better records would be available to support the larger projects.

In its Reply Brief, Staff says AIU's assertions regarding the differences between Staff's review in this case being different from any other case is speculation and should not be accorded any weight. Staff claims that although AIU does not admit it, a very similar review was conducted in its last rate proceeding where plant additions were subject to a disallowance for lack of supporting documentation. Staff also believes it is not appropriate for each of Staff's reviews to be constrained by that which has been performed in prior cases. According to Staff, AIU is attempting to convey the notion that not only should Staff's review in this case follow the same review as in the cases it cited, it is also claiming that Ms. Everson's adjustment must be disallowed since it was at odds with other Staff witnesses in this case. Staff contends this claim is irrelevant because Ms. Everson's review concerned whether AIU had sufficient documentation to support its plant additions, whereas Mr. Rockrohr's adjustments to plant additions concerned whether plant held for future use should be included in rate base and whether AIU was prudent in its purchasing of certain security installations. Staff claims that since the focus of each review was different, it is unrealistic to contend that one Staff member's analysis is flawed because it is different from another analysis conducted by another Staff member.

According to Staff, AIU witness Stafford incorrectly criticized Ms. Everson for including AmerenIP's 2004 gas plant additions when she applied the disallowance adjustment percentage to the total plant additions. He argued that IP was allowed a certain level of pro forma plant additions in its last rate case, Docket No. 04-0476. Taken to its logical conclusion, Staff says this argument incorrectly asserts that approved pro forma plant additions in a prior rate case do not require substantiation with supporting cost records in the next rate case. In Staff's view, this argument is unreasonable and inconsistent with the Commission's practice. Staff argues that pro forma amounts are essentially estimates of plant costs expected to occur within a defined period from the chosen historical test year and subject to certain restrictions as defined in 83 Ill. Adm. Code 287, "Rate Case Test Year." Staff claims the pro forma amounts for a specific plant can and do vary from the amount actually incurred for the same plant. Staff believes that the prior approval of a plant's cost when it was a pro forma item in a prior rate case has no bearing on its approval as an actual plant cost in a later rate case. In Staff's view, all plant costs for which a utility seeks rate recovery needs to be adequately supported regardless of whether they were once approved as pro forma amounts.

The amounts in the current filing for AmerenIP's 2004 plant additions, Staff argues, are not the same pro forma amounts that were allowed in the prior rate case. Staff says those amounts were allowed as pro forma amounts that would be placed into

service after the 2003 test year in that docket. Staff adds that AIU's response to Staff Data Request MHE 14.01 stated: "The current IP Gas 2004 capital additions amounts included in the current IP Gas filing are not identical to the pro forma plant additions that were considered in Docket No. 04-0476. The amounts related to the IP Gas 2004 capital additions included in the current filing include actual expenditures incurred in both 2003 and 2004 and placed in service in 2004." (Staff Initial Brief at 24, citing Staff Ex. 14.0R at 25) Staff maintains that its application of the adjustment percentage to all of AmerenIP gas plant additions is appropriate, since the plant additions in this case represent actual project costs which are not the same amounts as the pro forma amounts allowed in Docket No. 04-0476.

Staff states that in its review of the invoices and summary listings reflecting the invoices recorded by AIU, duplicate amounts were noted and disallowances were proposed. Ameren witness Batcher criticized Ms. Everson, for allegedly failing to document her procedures for identifying duplicate invoices rendering AIU unable to determine if she conducted adequate searches to find an adjustment to the duplicate on the summary listings. Staff asserts that Ms. Everson fully described in her rebuttal testimony the type of review she performed to make the determination that there was a duplicate invoice for which no offsetting adjustment existed on the summary listing. Staff asserts that Ms. Everson's review included a comparison of a suspected duplicate invoice with the previously reviewed invoice to verify the identical invoice, number, date, vendor, amount, and service or goods provided. Staff finds AIU's criticism to be without merit.

AIU, Staff argues, essentially faults Staff for not granting it the benefit of the doubt when Staff disallowed invoices that were not billed to the correct entity. Staff says that AIU cites the alleged practice of the IRS. Staff claims that AIU does not appear to fully understand that it is AIU's responsibility, not Staff's, to prove that the invoices it proffers as support for costs it seeks to recover from ratepayers are legitimate.

In Staff's view, the problem with AIU's position is apparent in Mr. Stafford's testimony that an invoice sent to AmerenCIPS but later charged to AmerenCILCO contained nothing that would indicate the invoice should have instead been sent and billed to AmerenCILCO. (Staff Initial Brief at 25-26, citing Staff Cross Ex. Stafford 1 and Tr. at 430-433) Staff provides another example where an invoice sent to Ameren Energy Resources' Purchasing Department but charged to AmerenIP contained no information indicating AmerenIP was the correct entity to be billed (Id., citing Staff Cross Ex. Stafford 2 and Tr. at 433-436) Given the dearth of information on the invoice as to which entity should correctly be charged, Staff argues that it can not in good conscience give AIU the benefit of the doubt and assume incorrectly billed invoices are automatically legitimate.

According to Staff, AIU claimed that the project manager determined whether billings to another Ameren company were appropriately associated with a particular project. Staff says that Mr. Stafford, however, stated on cross examination that there is

no information discernable from a review of the invoice to support this explanation. Staff says that unlike AIU, it can not presume that any review was performed or that any project manager direction was provided to substantiate AIU's claim. Staff asserts that no supporting documentation in the form of source documents, such as invoices that are either marked by the project manager or the accounts payable personnel, or some other internal document that would indicate the project manager's decision regarding which projects to assign costs was provided. Staff says AIU also inappropriately suggests that since the work was performed for the benefit of an AIU utility, it does not matter that an AmerenCILCO customer might be charged for project costs that benefit AmerenIP. Staff disagrees with that view and believes that ratepayers of one utility should not be penalized with higher rates as a consequence of AIU's failure to demonstrate that costs are recorded to the right utility.

According to Staff, Dr. Batcher also fails to recognize that there is a substantial difference between expense payments for tax purposes and the proof needed for rate recovery. For tax purposes, Staff says it makes little difference which company makes payment where a consolidated tax return is filed because in the end, all revenues and expenses are combined into a single tax return. Staff argues, however, that the Commission review for setting rates is a different standard. The Commission, Staff says, must decide which of the six AIU operations is to be credited for payment. Additionally, Staff says a decision must be made whether the payment is to be classified as an expense or a capitalized item. Staff asserts that if the payment is classified as an expense, questions concerning whether it is reflective of normal operations, whether it should be amortized, and whether the unamortized balance should be given a return must be answered. If the payment is classified as a capitalized item, Staff says decisions concerning the proper account and the depreciable life for purposes of calculating annual depreciation expense must be answered. Staff claims its task is more complex than just confirming payment by any one of the utilities and can not be accomplished unless the individual utilities provide the appropriate records in a timely manner.

Staff asserts that in many invoices it reviewed, the amounts did not match up to the amounts listed in the summary listing of invoices recorded by AIU. According to Staff, AIU claims only a partial amount on the invoice should be matched with the summary listing in the absence of any indication on the summary listing or on the invoice. Staff says AIU offered the explanation on Ameren Ex. 19.12 that the project manager made the determination of which charges on each invoice should be attributed to specific projects. Staff asserts, however, that Mr. Stafford concedes that the invoices contained no indication of the project manager's direction regarding specific invoices.

Staff indicates that Dr. Batcher asserts that where invoice amounts differ from the amounts shown on the summary listing of invoices, a partial amount should be allowed. In Staff's view, the suggestion that partial invoice amounts should be allowed is without merit. Staff acknowledges there could be legitimate reasons for the differences. Staff argues, however, that the knowledge that legitimate reasons for the discrepancy may exist does not substitute for documentary evidence that reconciles and substantiates

why invoice amounts differ from the amounts actually recorded by AIU on its books. Staff contends that AIU can not offer any credible explanation for some of the differences.

According to Staff, Dr. Batcher's assertion that some, if not all, of the differences would have been easily ascertainable by simply learning more about the business is also without merit. Staff claims this shows Dr. Batcher's lack of knowledge about which party bears the burden of proof. Staff maintains that AIU has responsibility to provide adequate documentation to support the costs included in its rate filing. Staff says that while it has spent considerable time and effort to make sense of AIU's plant records, Staff has no obligation to further expend its limited resources to help AIU satisfy its burden of proof.

Staff says Dr. Batcher asserts that Staff should have worked harder to find a way to make the illegible copies of invoices AIU provided legible. This assertion, Staff argues, indicates a fundamental misunderstanding about which party bears the burden of proof. According to Staff, AIU had every opportunity, before it filed the rate case, to ensure it had adequate, complete, and legible documentation for the costs it seeks to recover from ratepayers. After learning from Staff's direct testimony of the illegibility of some of its invoices, Staff says AIU once again had an opportunity to rectify the situation by providing legible invoices or alternative evidence that would adequately substantiate the costs in the illegible invoices. Instead, Staff claims AIU complained that Staff should have printed the illegible invoices on a different printer and played with various printer settings until it could read the invoice. Staff argues that if AIU's criticism were accepted then there would be no incentive for any utility to submit legible copies of any document to support costs it seeks to recover from ratepayers. Staff says reviewing and analyzing documentation of this magnitude is challenging enough without having to add what should be AIU's obligation: producing legible documentation of its costs.

Citing the Commission's decision in Docket No. 01-0701, Staff argues that it should not be ratepayers' responsibility to pay for late payment charges. Staff also refutes AIU's suggestion that Use Taxes and Purchasing Rate/Fixed Charge explain discrepancies in various invoices. In the latter case, Staff maintains that AIU failed to adequately explain the magnitude of such charges and when such charges are applied.

According to Staff, Dr. Batcher complained that Ms. Everson's review of invoices used a zero tolerance approach even though she was dealing with mergers and retired systems for storing the imaged invoices. According to Staff, a zero tolerance approach is reasonable, logical, and accepted in Illinois for reviewing plant records that a public utility has an obligation to retain, and for which AIU has the burden of proof to provide when it is requesting related plant costs be included in the determination of rates.

Staff says AIU criticized Ms. Everson for disallowing costs that are not supported by invoices as some are not retrievable from retired systems, indicating that alternative evidence should have been accepted, or if not extensive, that such missing items

should have simply been ignored in Staff's calculation of its disallowance. Staff maintains that the Commission's rules for record retention do not include any exemption for records simply because a utility chooses to retire a system, thus making retrieval more difficult or impossible. Staff restates that AIU and its predecessor companies all were subject to the record retention rules; so it is not valid that some allowance should be made for old or difficult to retrieve records.

Staff argues that since the summary listings were taken from AIU's general ledger, the general ledger is not a supporting source document for amounts that are drawn from the general ledger. In addition, Staff contends that continuing property records and retirement property unit records do not substitute for source documents, nor do they substantiate the cost of plant additions. According to Staff, the information generated through the queries to the general ledger systems was used to compile the list of invoices and voucher numbers. Staff adds that the underlying general ledger queries would simply be a repetition of the process that generated the list of invoices in the first place; it would not provide any additional support for the legitimacy of the costs.

Staff says the premise of AIU's position is that an invoice can be supported by the accounting records. Staff asserts that the source document for the accounting records is the invoice, not the other way around. AIU witness Nelson claims that the electronic transactions recorded on its general ledger can be relied upon to substantiate its costs as they can be independently verified through one of three different ways: 1) the accounts payable system, 2) the contractor system, and 3) the vendor's verifications. Staff notes that Mr. Nelson also testified that data from both the accounts payable system and the contractor system are fed into the general ledger's accounting system.

It is unclear to Staff how reports generated from either the accounts payable system or the contractor system would independently substantiate the costs recorded in the general ledger. Staff claims this reasoning is circular because there is no independent verification of the costs. As to the vendor's verifications, Staff says many vendors did not supply invoices with their affidavits that corroborate the costs in the general ledger. In addition, Staff states that Mr. Nelson testifies that AIU provided the information to the vendor regarding the costs the vendor verified. Staff adds that Mr. Nelson does not indicate how such vendors could have verified those costs over relatively long periods of time, some occurring as far back as 2003. Staff says Mr. Nelson is clear that using the data it has in its general ledger, accounts payable system, and contractor system, AIU prepared the information in the vendors' affidavits which it then had the vendors' sign. Staff believes this is circular reasoning and does not substantiate the costs in the general ledger.

Staff expresses concern about Ameren Ex. 19.12 in that AIU has not retained some of the invoices and has to rely on its vendors to provide invoices, many of which Staff says do not match to the amounts recorded to the general ledger and continuing property records. Staff indicates that AIU was not separately able to confirm from a vendor supplied invoice the reason for the difference, or whether the additional invoice

amount was either discounted for payment, or instead charged to another AmerenCILCO project. Based in part on this, Staff questions whether any of the invoices obtained in this manner can be relied upon to provide support for AIU's plant additions. Staff says the Commission can have no confidence that any such invoices are related to the amounts AIU claimed on its summary listings. Staff recommends disallowing these project totals from the determination of AIU's plant balances.

Staff indicates that in surrebuttal testimony, Mr. Stafford states that in response to Staff's concern regarding vendor-supplied invoices, AIU removed the costs associated with the vendor-supplied invoices that are being relied upon as support for project costs. Staff says it is unclear whether Mr. Stafford intends to mean that AIU has removed the costs associated with all vendor-supplied invoices that were provided to support project costs, or just ones that were disallowed by Staff. Staff claims it is nearly impossible without a line by line review of each item in the original summary sheets to determine if the claim that Mr. Stafford makes regarding the vendor-supplied invoices applies to all vendor-supplied invoices, or just the ones disallowed in Ms. Everson's calculation.

AIU witness Livasy provided rebuttal testimony that described the process that IP used for its electronic fund transfers ("EFTs"). IP's EFTs contain specific information that Mr. Livasy says was compiled or that existed such as work order numbers, invoice numbers, invoice dates, and vendor numbers to identify contractors. Staff complains that the testimony fails to provide any supporting documentation other than the results of queries on the same system that produced the amounts being tested.

Mr. Stafford claims that Ameren Ex. 19.13 provides support for the EFTs on IP projects. Staff says Ex. 19.13 is a spreadsheet with information on work order numbers, invoice numbers, invoice dates, general ledger amounts, vendor numbers and names, batch numbers, approvals, and the paying entity. The problem with this listing, Staff argues, is that this information came from the general ledger itself, not from an independent source that could corroborate its veracity. Staff says no invoices or contracts or any other evidence that the transfers were reviewed or approved were provided. Staff contends that an internally-generated document such as Ameren Ex. 19.13 which was produced from the same general ledger as the amounts in the general ledger in question only provides support that entries were made, and that funds were transferred from the AIU utility. In Staff's view, Ex. 19.13 does not provide support for the validity of the cost amount, or the applicability of the amount to a specific project, since no vendor invoices are provided. In other words, Staff does not believe the general ledger can substitute for independent third party evidence. According to Staff, there is no audit trail for the electronic transactions or presumably AIU would have provided it with its rebuttal testimony instead of relying on descriptions of the process.

Staff says that in response to Staff Data Request MHE 14.03, which asked AIU to produce the invoices to support its plant additions paid for by EFTs, AIU objected and stated that it was unable to immediately obtain that information. Staff indicates that AIU also stated that vendor payments are based on documented internal processes that

provide appropriate controls and authorizations for payment, satisfying vendors, auditors, taxing bodies and regulators including the Commission. Staff asserts that nothing was provided to document those alleged appropriate controls and authorizations. Staff says AIU could produce no Commission order to support its contention that this process had been approved by the Commission and could produce no written communication from the Commission's Accounting Department Manager that indicated approval of the electronic process.

Staff says much of AIU's surrebuttal testimony is essentially supplemental data that was requested by Staff in the MHE 3 series of data requests. Staff claims it is not in a position to know what is the universe of supporting documents for AIU's requested plant additions. Assuming Staff even knows the universe of such documentation, which Staff says it does not, Staff claims the magnitude of the information that needs to be sifted through to uncover problems, such as missing invoices or invoices with discrepancies, takes a significant amount of time. Staff claims it is not in a position to know how many plant assets are involved, thus, Staff can not know how many invoices Staff is supposed to get in support of such assets and related costs. Staff adds that thousands of line items reflecting plant additions and related costs are involved.

According to Staff, this complicated situation is further exacerbated by the fact that many data request responses were supplemented by AIU, and at times, supplemental responses were replaced by corrected supplemental responses. At the same time, Staff says key AIU rebuttal testimony and exhibits were revised after they were filed. In other words, Staff says it has had to contend with a moving target.

Staff asserts that at each point it received responses or supplemental data to prior data responses or to prior AIU testimony, Staff had no basis at those points in time to doubt the completeness of the responses and pursue additional responses from AIU through other means of discovery, such as a motion to compel. Staff believes it is only upon hindsight that one can see that AIU was not forthcoming in its provision of information necessary to adequately support its requested plant additions.

On July 1, 2008, Staff indicates it conducted cross-examination of the AIU witnesses. The purpose of the cross-examination, Staff claims, was not to provide an analysis of the information, but rather to illustrate how such an analysis should be conducted, the difficulty of the analysis, and how much time it would consume. Staff asserts that AIU has consistently provided faulty support for its costs in this proceeding.

Staff recommends that the adjustment proposed in Staff rebuttal testimony be adopted unless the decision maker conducts an analysis of the information provided in AIU's surrebuttal testimony. Staff asserts the analysis of this information would be time consuming and meticulous. In order to determine whether costs submitted with the surrebuttal testimony are supported, Staff says one would begin by comparing Ameren Ex. 43.6, Schedules 1-6 with Ameren Ex. 19.12, Schedules 1-6, to determine for each line item whether Ex. 43.6 contains better information than what was provided in Ex. 19.12. If new information is provided for a given line item, then, Staff says, Ex. 43.6,

Schedules 7 and 8 must be reviewed to locate the new support provided. If the support is located, then Staff states that Ex. 19.12, Schedules 8 through 13 must be reviewed to confirm that the information has not already been provided. Similarly, Staff claims that AIU's production in response to the MHE 3 series (Staff Cross Stafford Group Ex. 5) must be reviewed to determine that the information was not provided in that production. Staff indicates the documents within these exhibits are organized by utility, utility type, and Project Number. In addition, Staff says it must be confirmed that the cost was not previously allowed in Staff's review. If an invoice has been provided with Ameren Ex. 43.6, which has not been previously provided nor accepted by Staff, then Staff says the invoice should be reviewed to determine whether the amount is now supported. Staff asserts that since the information provided in Ameren Ex. 43.6, Schedules 1-8 contains no identification of which line items are new or previously provided, review of this information is difficult and extremely time-consuming.

Staff says the information provided in Mr. Nelson's surrebuttal are affidavits of vendors provided in lieu of actual or electronic invoices to support some of AmerenIP's EFTs. In addition to the concerns discussed above, the lack of specificity in the wording of the affidavit leads Staff to have concerns regarding the accuracy and reliability of these affidavits. According to Staff, these affidavits essentially constitute hearsay and can not be relied upon by the Commission as adequate support of AmerenIP's EFTs for which it could not locate supporting invoices.

In its Reply Brief, Staff says that AIU protests that Staff did not provide AIU with a listing of each and every invoice that Staff disallowed and contends that this shortcoming limited the ability of AIU to refute Ms. Everson's analysis. Staff believes AIU's argument is unfounded. Staff argues that AIU has sufficient information to determine which specific invoices were disallowed by Staff. Staff says the argument seems to be that Staff should have provided AIU with a detailed listing of each individual amount disallowed rather than the listing of amounts that Staff allowed. According to Staff, AIU's allegation that it is prejudiced by the presentation of Staff's adjustment in its work papers does not bear scrutiny. Staff claims AIU was capable of looking through the Summary Listings, identifying which invoices were disallowed, and then checking to see if they were duplicates, bills to the wrong company, etc.

In Staff's view, the complaint about Staff's work papers must be considered in context; the Summary Lists and the format which Ms. Everson used to identify her findings came directly from AIU. Staff claims there is no difference between using a slash to indicate Staff identified an invoice on a Summary Listing than AIU using a check to indicate the invoice had been provided. Staff avers that AIU's argument, that the very format that it found to be acceptable when making its production was unacceptable when used by Staff, is unpersuasive. Staff says its proposed disallowance was of a percentage of unsupported plant costs; it is not a disallowance of specific invoices or specific unsupported plant costs.

Staff states that while AIU did provide voluminous information throughout the case, it was provided without any roadmap until rebuttal. Staff complains that each new

production was provided with nothing to distinguish between new and old information. According to Staff, AIU seemingly equates the quantity of its documentation with quality. According to Staff, the explanations provided in Ameren Ex. 19.12 should have been the starting point provided to Staff for the analysis, but, the descriptions and the road map were provided for the first time in AIU's rebuttal.

Staff claims that AIU's Initial Brief fails to recognize that Staff modified its plant adjustment to eliminate any double-counting of Ms. Everson's adjustment for plant additions since the last rate case and Mr. Rockrohr's adjustments for plant held for future use and security installations. According to Staff, AIU cites Mr. Stafford's rebuttal testimony for this proposition and ignores Staff's rebuttal testimony where Ms. Everson indicates that she made changes to eliminate any double counting or double adjusting of plant additions prior to 2005. Staff says this modification is incorporated into Staff's rebuttal schedules and AIU's assertion regarding double counting is erroneous.

In its Initial Brief, Staff objects to AIU's practice of capitalizing the cost of employee meals. Staff says AIU could not cite a specific provision in the USOA that supports such a practice.

Staff recommends that AIU conduct an annual internal audit of its plant additions and retirements for each of its operating utilities with a copy of the report to be provided to the Manager of the Accounting Department of the Commission by June 30, of each year with the 2007 report to be submitted by December 30, 2008. Staff says the work papers of such audits should be made available and provided to Staff upon request. Staff asserts that requiring AIU to conduct its own internal audit will provide an opportunity for AIU to improve its record keeping skills. The annual reports submitted to the Commission, Staff avers, will provide some assurance to the Commission that AIU is taking steps during the time period between rate cases to improve its plant records. An improvement in record retention, Staff claims, should decrease the contentiousness of plant additions in the next rate case. Staff indicates that AIU witness Steinke stated that AIU has no objection to Staff's recommendation for an annual internal audit.

c. CUB's Position

According to CUB, AIU fails to provide sufficient cost justification to support the cost of plant additions since the last rate case, and therefore these costs should be disallowed. Some of the specific deficiencies include: 1) duplicate invoices, 2) billings to the wrong company, 3) invoices not found that correspond to the listing of invoices provided, 4) amounts on invoices that do not correspond to the listing, 5) project not determinable from the invoice or the invoice is not related to the project, 6) illegible invoices, and 7) certain AmerenIP project amounts that were paid via electronic transfer without a supporting invoice. CUB states that AIU presents Schedules 2.03E and 2.03G asking the Commission to reduce each utility's rate base, but AIU does not provide supporting documentation to allow adjustments to reduce each utility's rate base by the percentage of additions that have occurred since the last rate case and therefore should be disallowed.

d. Commission Conclusion

Because it believes that the costs associated with certain plant additions made since the last rate case have not been adequately documented, Staff recommends that such costs should be excluded from rate base. With very limited exception, AIU disagrees with Staff's position, arguing that it has adequately documented the costs associated with most plant investments. Staff has additional recommendations including that the costs excluded from rate base should be permanently written off and the assessment of fines for AIU's failure to maintain its books and records in the manner required by Commission rules. For the most part, AIU objects to Staff's additional recommendations.

As discussed extensively above, in evaluating AIU's capital investments since the last rate cases, Staff reviewed a sample of projects with total costs exceeding $500,000 for each of the three utilities. Staff concluded that a portion of the costs associated with certain projects were inadequately supported. To develop its proposed adjustments to rate base, Staff applied the percentage of what it considered an inadequately documented amount of plant investment incurred by each utility since its last respective rate case.

As an initial matter, AIU objects to Staff's proposal to apply the percentage developed from projects with costs exceeding $500,000 to the entire universe of plant additions since the last rate case, including those with costs below $500,000. AIU argues that at most, Staff's proposed percentage disallowances should be applied only to those projects with costs exceeding $500,000. Staff believes its assumption that the documentation for larger cost projects would be superior to the documentation for lower cost projects, and justifies the application of its percentage disallowances to both sizes of projects.

Having reviewed the arguments of the parties, the Commission finds that the record does not support Staff's proposal to apply the proposed percentage of disallowed plant costs to projects with costs less than $500,000 since the last rate case. There is no objection to applying a percentage of disallowed costs to the universe of projects with costs greater than $500,000 (from which the sample was derived), and the Commission finds that proposal reasonable. The preponderance of evidence, specifically that regarding sampling methodology, does not support applying a percentage of disallowed costs to projects with costs less than $500,000. The assumption underlying this portion of the proposed adjustment is not adequately supported by the record.

In its Brief on Exceptions, Staff claims there is an inconsistency in the Proposed Order asserting that it rejects a portion of Staff's proposed adjustment to plant additions because Staff used a judgmental based sample rather than a statistical based sample, but did not reject AIU's judgmental based sample as support for AMS costs. The Commission understands Staff's view but believes its concern is misplaced and

oversimplifies the situation in which the Commission finds itself. With respect to both of these issues, as is typically the case, the record is not optimal but the Commission must make the best or reasonable decision based upon the record. With regard to plant additions, the Commission believes it is reasonable to apply Staff's proposed disallowance percentage to projects with costs greater than $500,000 but not to projects with costs less than $500,000. With respect to AMS costs, which are discussed more fully below, the Commission's only alternative to accepting AIU's sampling approach is to accept Staff's proposed allocation factor for AMS costs, which the Commission finds wholly unacceptable. Additionally, the Commission notes that in addition to the study of specific AMS costs performed by Concentric, it also performed several benchmarking studies that also provided important support for AIU's assertion that AMS costs allocated to AIU are reasonable. Thus, the Commission's decisions on these two issues must be viewed in the context of the available alternatives as well as the entire record related to each issue.

In its Brief on Exceptions, AIU identifies what it calls calculation errors and clarifications in the appendices to the Proposed Order. Among them is an assertion that the Proposed Order removes from rate base certain plant costs twice. AIU claims that because the starting point for removing plant from rate base in the Proposed Order is its rebuttal position, which already removes from rate base certain plant costs in agreement with Staff, AIU explains that acceptance of Staff's position would remove some of the plant costs twice. In its Brief in Reply to Exceptions, Staff suggests that the adjustment in the Proposed Order is correct and recommends rejecting the proposed change contained in AIU's Brief on Exceptions.

The Commission has reviewed the record and it appears that AIU is correct. Specifically, the Proposed Order applies Staff's proposed disallowance percentages to all AIU projects with costs in excess of $500,000. As AIU suggests, however, the appendices attached to the Proposed Order begin with AIU's rebuttal position. AIU's rebuttal testimony acknowledges that certain plant costs can not be supported; therefore, AIU removed such plant costs from the plant costs it sought to include in rate base in direct testimony. (See Ameren Ex. 19.12 Revised and Ameren Ex. 36.1) Thus, by applying Staff's proposed adjustment percentage, developed in its direct testimony, to all projects with costs exceeding $500,000, the Proposed Order excludes certain plant costs from rate base twice. The Commission finds that in order to avoid removing certain costs from rate base twice, it is necessary to correct the Proposed Order and this correction is reflected in the appendices attached hereto.

Staff proposes that certain costs associated with EFTs by AmerenIP be excluded from rate base because there is inadequate documentary support. AIU argues, among other things, that Staff has not previously proposed similar adjustments, that it thoroughly explained how the EFT process works, and that such costs tie into the accounts payable system and other AIU records.

As an initial matter, the Commission has no objection to AIU, or any other utility, making payments electronically or maintaining records in an electronic format. When

questioned by Staff or an intervener in a rate proceeding, however, AIU must be able to document the underlying expenditure. As part of its support for EFTs, AIU provided third party or vendor copies of invoices along with affidavits of the vendors. With regard to this type of evidence, Staff recommends that the Commission treat this information as hearsay and give it no weight when deciding which costs should be included in rate base. The Commission has reviewed the disputed information and finds that it should be given little weight. The documents provided could be accurate representations or copies of invoices; however, it is not clear that is the case. The manner in which AIU solicited its vendors suggests to the Commission that vendors in all likelihood felt pressured to respond in a manner that AIU would deem favorable. The Commission would expect those vendors to want to please AIU so that they could maintain a business relationship. Of course, since the individuals who signed the affidavits were not present, it is impossible to know this or anything else about the veracity of the documents provided by the vendors.

With regard to AIU's assertion that the EFTs are supported by the fact that they match other AIU records, the Commission does not find this argument particularly compelling. As Staff suggests, simply because all of AIU's internal numbers match does not dispel the possibility that AIU's numbers are wrong. An underlying invoice would provide the necessary verification supporting AIU's internal records. Absent such documentation, it is impossible to discount that an improper EFT or an EFT for the wrong amount was initiated, processed, and completed.

Even putting these problems aside, the Commission is concerned that AIU expects the administrative law judges and the Commissioners to review individual invoices and determine whether such invoices are supportive of costs that Staff claims should be disallowed. This is tied directly to the remaining disputed amounts between AIU and Staff; those amounts AIU claims are adequately supported by the invoices provided along with AIU's surrebuttal. In its Reply Brief, AIU states that the Commission can not ignore this evidence and suggests that reviewing it would not be as time consuming and meticulous as Staff suggests. Having undertaken that effort, the Commission disagrees with AIU. The amount of information attached to AIU's surrebuttal testimony is quite voluminous. The more important problem, however, is that there is no context in which the information can be evaluated by the decision maker. In addition to the vendor provided invoices discussed immediately above, there are clearly other invoices attached to AIU's surrebuttal testimony. It is impossible, however, for the decision maker to determine if these invoices correspond to the specific disallowances proposed by Staff. The decision maker has no idea if an invoice for contract labor or any other specific cost corresponds to the specific costs Staff testifies were not previously provided, whether an invoice is duplicative of a previously provided invoice, or for that matter, whether an invoice is totally unrelated to a contested issue. In summary, while AIU provided additional information along with its surrebuttal testimony, the Commission is unable to determine that this information supports the costs that were previously unsupported. Accordingly, the Commission accepts Staff's adjustment on this issue.

Staff also recommends that AIU be required to permanently write-off any disallowance ordered in this proceeding. AIU opposes this proposal, arguing among other things, that it is too harsh. The Commission rejects the proposal to require a permanent write-off. The argument that AIU will not likely be able to provide superior documentation of costs in future rate cases, while superficially appealing, must be rejected. First, AIU argues that it already provided adequate documentation supporting its expenditures along with its surrebuttal testimony. While the Commission has been unable to determine that that is true in this proceeding, it would be unfair to require AIU to permanently write-off investment for which adequate documentation may simply have been provided too late in this proceeding. Second, given the incentive AIU should have to have costs included in rate base, it is possible it would expend sufficient effort between the conclusion of this case and the beginning of its next rate case to uncover adequate documentation of costs disallowed here. To properly balance the interests of ratepayers and shareholders, the Commission rejects Staff recommendation to order a permanent write-off.

Staff argues that AIU is in violation of the Commission's rules regarding records retention and that the Commission should therefore fine AIU. AIU acknowledges some record keeping problems but, nevertheless insists it is not in violation of the Commission's rules and objects to the proposal for a fine. In the context of this rate proceeding, the Commission declines to be further drawn into this dispute between Staff and AIU and rejects Staff's recommendation at this time. Other avenues and forums outside a contested rate case are available to Staff if it wishes to pursue this issue further. The Commission simply reminds AIU that it is expected to comply with all Commission rules.

Staff's recommendation that AIU conduct an annual internal audit of its plant additions and retirements for each of its operating utilities and provide a copy of the report to the Manager of the Accounting Department of the Commission by June 30 of each year, with the 2007 report to be submitted by December 30, 2008, is accepted. The work papers of such audits should be made available and provided to Staff upon request. Finally, any suggestion that ratepayers should be burdened with undocumented costs is not well taken. If costs can not be documented, they will not be reflected in rates, regardless of ownership changes or anything else.

As for Staff's late arising concern regarding the capitalization of employee meals, the record of this proceeding contains insufficient information to make an informed decision and insufficient data to make an adjustment if the Commission decided one were warranted. In any event, the Commission urges AIU and Staff to consider whether it is appropriate to include in rate base the capitalized cost of employee meals. For AIU, this is something it may wish to consider investigating immediately and, perhaps discussing with Staff, in an attempt to avoid an unnecessarily contested issue in its next rate case.

2. Plant Additions Disallowed in the Last Rate Case

a. Staff's Position

Staff witness Everson proposes reducing AIU's electric rate bases for plant additions that were disallowed in AIU's last electric delivery service rate proceeding, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), and which she says AIU was still unable to provide supporting documentation. Staff reports that in rebuttal testimony, AIU witness Stafford agrees with Staff's adjustment for AmerenCIPS and agrees that a portion of the plant additions are still unsupported for AmerenCILCO and AmerenIP. Mr. Stafford recalculates Staff's proposed disallowance presented on Staff Exhibit 2.0R, Schedule 2.07 to reflect the portion of such additions that AIU concedes are unsupported, but reduces the proposed disallowances to reflect additional supporting documentation that AIU provided. Staff does not recommend accepting all of the additional supporting documentation that AIU provided. Staff claims the amounts on some of the invoices provided do not match with the amount of the asset listing. According to Staff, AIU has not provided the specific reasons that explain why a particular invoice amount does not agree with the asset listing. Staff says it still can not verify that the costs of plant additions that were put into service at least four years ago that the Commission disallowed in the prior AIU electric rate proceedings are the right costs to be included in rate base.

According to Staff, Mr. Stafford complains that Ms. Everson does not provide insight into which submitted invoices were accepted or rejected. Mr. Stafford claims that Staff does not appear to have conducted any review of the additional evidence AIU submitted. Staff says it had already reviewed the evidence presented in the previous rate proceedings and had also reviewed the evidence presented in the preparation of direct testimony. Staff claims that AIU admits that it did not have appropriate documentation for all of the contested plant additions and offers a multitude of reasons why a difference could exist. Staff says AIU does not identify the reason for each of the differences. Staff claims it investigated those same general reasons that AIU provided for the plant additions since the last rate case and found extensive follow-up and analysis was required. Staff submits that it should not have to work to prove that documentation does not exist. In Staff's view, if documentation exists, then AIU should provide it. Staff submits that if AIU does not provide documentation, then the additions should be disallowed. Staff states that these plant additions have been in service for over four years and AIU has been working on this case since January/February of 2007. According to Staff, the Commission should find that the burden rests with AIU as required by Section 9-201(c) of the Act.

In its Reply Brief, Staff insists that Ms. Everson reviewed only a sampling of the information and indicated that AIU had attempted to rebut this adjustment with reasons similar to those it used to rebut the disallowance of a percentage of plant additions since the last rate case. Staff states that the new information provided reinforces its concerns about AIU's inability to support plant additions. Staff says AIU's responses to Staff's inquiries about the rebuttal information reinforced instead of quelled Staff's concerns.

Staff asserts that AIU's responses regarding the deficiencies either retracted previous explanations or offered vague and non-specific information which cast doubt on the integrity of all of the explanations offered to the extent that Staff could not accept the explanations.

b. CUB's Position

In its Initial Brief, CUB supports Staff's proposed adjustments to rate base.

c. AIU's Position

AIU alleges that as with her adjustment for additions since the last rate case, Ms. Everson has not identified which specific invoices are at issue. AIU asserts that although it asked to be told which of Staff's two reasons for rejecting an invoice applied to each rejected invoice, Staff did not provide sufficient information to enable AIU to respond to Staff's proposed disallowance. AIU complains that it was necessary to conduct an analysis of the three projects for both AmerenCILCO and AmerenIP where Staff does not fully accept all additional supporting documentation.

According to AIU, it appears the primary reason Staff deemed an amount to be unsupported for AmerenCILCO is that taxes were paid for an invoice amount. According to AIU, this is not a valid reason to exclude an amount as unsupported. AIU says if AmerenCILCO was exempt from tax it would be a valid reason, but AmerenCILCO does have to pay tax where applicable. A review of two of the amounts in question, AIU states, indicates the amount deemed to be unsupported is exactly equal to 6.25% of the accepted amount for the invoice in question, which corresponds to the tax rate in effect at the time of said purchase.

With regard to AmerenIP, AIU claims that the primary reasons Staff deemed an amount to be unsupported are that two or more invoices are split between projects, or that project and/or work order numbers do not directly correspond to the project in question. AIU argues the fact that two or more invoices are split between projects is not a valid reason to exclude an amount as unsupported. According to AIU, if work is performed by a supplier for more than one project, then it is appropriate that such amounts should be accounted for separately. AIU alleges that in each of these examples, the supervisory personnel that approved said invoice or invoices determined that such costs should be split, with only a portion assigned to the project in question. AIU asserts that to handle this situation any differently would be incorrect, and is no reason to disallow a cost for recovery.

AIU argues that although Ms. Everson continues to recommend disallowance of plant additions disallowed in the last rate case in her rebuttal testimony, she does not challenge or respond to the positions or arguments Mr. Stafford makes in his rebuttal testimony. AIU alleges that her proposed adjustments for previously disallowed additions do not consider additional supporting documentation provided by AIU in

rebuttal. AIU claims Staff has provided no meaningful support for these proposed disallowances.

Ms. Everson, AIU says, claims that AIU's rebuttal on this issue is similar to that regarding plant additions since the last rate case. AIU asserts that its rebuttal on this issue is quite different from its rebuttal regarding plant additions since the last rate case. AIU states that for the 20 projects identified as unsupported in Staff Ex. 14.0, Schedule 14.07, AIU provides additional evidence in rebuttal supporting a portion of the proposed disallowed dollars for 6 of the 20 projects. For the remaining projects and dollars, AIU says it reflects an adjustment to reduce plant additions included in rate base in Mr. Stafford's rebuttal testimony. AIU claims 18 invoices support dollars at issue in six projects. This additional documentation, AIU argues, should have confirmed for Staff that neither of Staff's previously stated reasons for disallowance was valid for the majority of the costs. According to AIU, in the amounts cited, either the amount at issue was fully explained and reconciled, or neither reason given by Staff for the disallowance applied to the invoice at issue.

In its Reply Brief, AIU agrees that some of the previously disallowed additions remain unsupported. AIU says it is not seeking rate base recovery for those items; however, it is seeking recovery for additions that it claims are now supported. AIU asserts it has supported $1,019,753 in plant additions that were disallowed in the last rate case and Staff provides no specific basis why this evidence is insufficient. Because Staff's adjustment is calculated as a percentage of total plant additions selected for review, AIU believes Staff's proposed adjustment should therefore be reduced from $39,554,000 to $22,991,000.

d. Commission Conclusion

Staff proposes reducing AIU's electric rate bases for plant additions that were disallowed in AIU's last electric delivery service rate proceeding and for which it says AIU was unable to provide supporting documentation in this proceeding. Staff reports that in rebuttal testimony, AIU agrees with Staff's adjustment for AmerenCIPS and agrees that a portion of the plant additions are still unsupported for AmerenCILCO and AmerenIP. Staff does not recommend accepting all of the additional supporting documentation that AIU provided. Staff says it can not verify that certain costs disallowed in the prior AIU electric rate proceedings are the right costs to be included in rate base. According to Staff, the costs were not supported either because the invoices did not correspond with the listing of invoices provided or because the amounts on the invoices did not correspond to the amounts on the listing.

The Commission has reviewed the testimony as well as the arguments regarding plant investment that was excluded from rate base in the previous rate case. Despite AIU's assertion that it has adequately documented these investments, it is not clear to the Commission that is the case. As the Commission understands it, Ameren Ex. 19.6, Schedules 4 through 7, is intended to provide the documentation. The Commission, however, is unable to sort through the hundreds of pages of invoices and determine if

these documents establish the costs previously disallowed are adequately documented. While documents were provided, the Commission is unable to determine even if the invoices provided relate to the plant at issue. AIU is mistaken in its apparent assumption that it can provide a large number of invoices and the Commission will either assume the invoices support the costs at issue or can somehow effectively evaluate the invoices with no explanation. The Commission has no basis to make a determination that the invoices and documents support the costs at issue here. As a result, the Commission accepts Staff's proposal to exclude from rate base the disputed costs that were also disallowed in AIU's last rate case. Staff's proposed adjustments are quantified in each of the three Schedules 14.07-E attached to Staff Ex. 14.0.

3. Property Held for Future Use

a. AIU's Position

On April 3, 2006, AmerenCIPS purchased 31.28 acres, near the intersection of Seminary Road and Bockstruck Lane in North Alton, Illinois, for $375,935. The land was purchased for AmerenCIPS to construct a new substation to be known as the North Alton Bulk Distribution Substation ("Substation"). AIU anticipates that the Substation will be in service by 2014. AIU indicates that the Substation is necessary to serve existing and future load in the northern and northwestern portions of Madison County.

AIU proposes that AmerenCIPS' investment in the land be included in rate base even though it is not currently being used to provide utility service. AIU argues that plant held for future use is a traditional component of rate base, which allows a utility to implement prudent, long-term planning strategies. Under Chicago v. Illinois Commerce Commission, 133 Ill. App. 3d 435, 441 (1st Dist. 1985), AIU understands that plant held for future use may be included in rate base if there is a plan to put it into service within 10 years of the test year. AIU also contends the Commission has also allowed plant held for future use to be included in rate base even beyond this 10-year period where the investment is shown to be "reasonable and the property should be retained; that a significant lead time was required between acquisition of a plant site and plant completion; and that long-range planning was necessary." (Id.)

Due to the long lead-times required for routing and obtaining a certificate of convenience and necessity from the Commission for a 138kV transmission to supply the Substation, as well as the lead times for engineering, design, material acquisition, and substation construction, AIU indicates that AmerenCIPS must beginning planning for future load growth in the area now. AIU acknowledges that the parcel it purchased to accommodate its plans is most likely larger than what it will need for the Substation, but asserts that the seller wanted to sell the entire tract and not split the property. In AIU's view, it was necessary, prudent, and useful to ratepayers to purchase the entire parcel for purposes of building the Substation.

AIU urges the Commission to reject Staff's recommendation to disallow this $375,935 investment from rate base. AIU avers that Staff witness Rockrohr does not

claim that the purchase of the property at issue was not prudent, but rather Staff takes the position that the land should be removed from rate base because it will not be used and useful until the Substation is constructed and placed in service. AIU argues that Mr. Rockrohr does not apply the appropriate standard when evaluating plant held for future use, and that to apply his standard would be the same thing as disallowing plant held for future use altogether.

AIU also disagrees with Mr. Rockrohr's claim that inclusion in rate base would be more appropriate in a future rate proceeding. AIU states further that he appears to take issue with the Commission's policy on plant held for future use itself. AIU submits that there is no evidence supporting Mr. Rockrohr's claim that a shorter standard time period for including plant held for future use in rate base is warranted where rate cases are filed more frequently.

b. Staff's Position

Staff recommends that the Commission disallow from rate base $375,935 relating to a parcel of property on which AmerenCIPS intends to build a substation to be in service in 2014 or after. Mr. Rockrohr recommends that the Commission disallow the cost for this parcel for various reasons. He submits that AIU did not demonstrate that the property will ever actually be used for the Substation, nor did AIU provide sufficient evidence to show when the Substation will be in service, should it even be built. Mr. Rockrohr also contends that the evidence shows that even if the Substation is built, AmerenCIPS will utilize only a fraction of the parcel that it purchased. He adds that AmerenCIPS' cost for the property would be more appropriately included in a future rate case at a time when AmerenCIPS can adequately demonstrate that the subject parcel will be placed in service within ten years of the test year. He suggests that the Commission require AmerenCIPS to sell approximately 90% of the parcel (since AmerenCIPS will not need more than 10% for the Substation) and remove from rate base an amount equivalent to the proceeds from the sale. He adds that AmerenCIPS' cost for the property would be more appropriately included in a future rate case at a time when AmerenCIPS' actual use of the property is known.

c. Commission Conclusion

The issue here is whether AIU adequately demonstrated that its planned Substation will be built and in service on the parcel of land purchased within 10 years of the test year. AIU supplied the Commission with evidence showing that current and anticipated load growth in the area is driving the need for a new bulk supply substation. The Commission believes that AIU's intention to build the Substation is an example of prudent planning that benefits customers. The Commission also finds that AIU's investment in the property is reasonable and the evidence supports a finding that the timing of the acquisition is appropriate.

The Commission does not share Staff's concern that the Substation is not expected to occupy the entire parcel of land. As the Commission sees it, many factors

can influence a utility plan for locating and acquiring land for a substation. Such factors include the location and availability of property, as well as the ability to obtain property rights. Although the Commission believes it was reasonable for AIU to purchase the entire tract at issue here, the Commission directs AIU to use its best efforts to utilize or dispose of the remainder of the tract in a manner that best benefits customers. How AIU decides to deal with the remainder of the tract is an issue that can be revisited in future rate cases. The Commission concludes that AmerenCIPS' investment for the planned Substation should be included in rate base and Staff's proposed disallowance is rejected.

4. Security System Installations

a. AIU's Position

AIU argues that it is required, both as a matter of law and as a matter of prudent, safe, and reliable operations, to have effective security systems for its facilities as described in Section 4-101 of the Act. AIU submits that these provisions require it to have on-site safeguards to restrict physical access to critical infrastructure, and for the electric utilities to follow the most current security standards set forth by the North American Electric Reliability Corporation ("NERC"). According to AIU, the security systems that it installed are designed to meet these requirements. Because the security systems represent prudent investment in needed protection of its facilities, AIU argues that it is entitled to have the security investment included in rate base.

In support of its argument, AIU points out that electric transmission lines, substations, gas pipelines, storage fields and other facilities are considered critical energy infrastructure. AIU submits that securing such critical infrastructure is necessary not just to ensure that customers have adequate and reliable service, but also that interconnected facilities of other utilities throughout the region and the country are protected. AIU points out that Staff witness Rockrohr does not compare AIU security systems or their costs to those of non-AIU utilities, nor did he conduct any outside research into, or review publications related to, security systems. AIU notes that Mr. Rockrohr agrees that protection of AIU's critical infrastructure from terrorist attack and criminal activity is necessary, and he further agrees that AIU's customers benefit from measures to protect AIU's facilities. AIU argues that the evidence in this case shows that its security systems are reasonable and necessary to protect its critical infrastructure and other facilities and personnel. AIU submits that Staff’s lack of a meaningful comparison of other utilities to AIU demonstrates that Staff has no basis to recommend disallowance of security costs.

b. Staff's Position

Staff recommends that the Commission disallow $178,173 from AmerenCILCO’s proposed rate base, $881,686 from AmerenCIPS’ proposed rate base, and $417,528 from AmerenIP’s proposed rate base, which represents installation costs of state-of-the-art security systems at each utility’s facilities. Staff contends that AIU demonstrated no

need for these security systems, considered no alternative systems, and did not even know the ongoing costs associated with utilizing them. Staff argues that the NERC guidelines do not state that each utility must, or even should, install card readers and closed circuit television cameras at all of its facilities. Instead, Staff notes that the NERC guidelines list types of security systems that a utility might consider when evaluating the adequacy of its existing security. In support of its proposal, Staff points out that even though AIU witness Mullenschlader claims the security systems were installed to satisfy the requirements of NERC guidelines, when asked if AmerenCIPS had experienced security issues at the three facilities associated with AmerenCIPS' expenditure of $608,799, Mr. Mullenschlader stated that no specific data was available. After reviewing all the information that AIU provided about the security systems that were installed at facilities within the operating areas of AmerenCILCO, AmerenCIPS, and AmerenIP, Mr. Rockrohr remains unconvinced that the security system investments were prudent and used and useful in providing service to customers. He believes that these security system costs would more appropriately be paid for by the shareholders of each utility than by customers.

c. Commission Conclusion

The Commission agrees that securing AIU's infrastructure is necessary to ensure that customers have adequate and reliable service. The Commission also believes that AIU's security system costs are a prudent investment, that the security systems benefit customers, and that these systems are used and useful in providing service to customers. Contrary to Staff's suggestion, the need for maintaining the security of utility assets has increased dramatically and what may have been considered excessive or state of the art only a few years ago is now necessary and appropriate.

The Commission, however, is concerned that AIU considered no alternatives to the security system it installed. The Commission understands that AIU chose to use the same vendor that it has previously used; however, in the future AIU should undertake an investigation regarding both the need for and the cost of alternative security systems and be able to better document and justify decisions it makes regarding security investments.

5. Cash Working Capital

a. AIU's Position

In its direct case, AIU presented the results of a lead-lag study to quantify the CWC requirements of each of the gas and electric businesses of AIU. AIU states that CWC reflects the amount of funds required to finance the day-to-day operations of AIU. AIU relates that the two most commonly used methodologies by which to determine a company's CWC requirements are referred to as the "Net Lag" and "Gross Lag" methodologies. AIU adds that the CWC requirements for each of the utilities were calculated employing the Net Lag methodology. Ameren Ex. 3.5 shows the calculation of CWC requirements under the Net Lag methodology. If prepared properly, AIU claims

the two methodologies should produce identical results. Ameren Exs. 5.7, 5.8, and 5.9 set forth the calculation of AIU's CWC requirements under the Gross Lag methodology. AIU reports that both methodologies yielded the same results.

Staff witness Kahle has suggested six modifications to the CWC requirements proposed by AIU: (1) use of the Gross Lag methodology rather than the Net Lag methodology; (2) inclusion of pass-through taxes in the calculation of the revenue lag with zero lag days; (3) inclusion of capitalized payroll in the level of payroll expenses used to determine AIU's CWC requirements; (4) correction of the expense lead associated with Employee Benefits; (5) reflection of the impact of Transitional Funding Trust Notes ("TFTN") interest expense; and (6) reflection of Staff's proposed levels of operating expenses in the CWC analysis.

AIU agrees with Mr. Kahle's correction of the expense lead associated with Employee Benefits. AIU says the expense lead originally filed contained a cell reference error that needed to be updated to reflect the corrected expense lead days. AIU believes Mr. Kahle has accurately reflected the expense lead as 24.746 days. AIU indicates that adjusting the expense lead for Employee Benefits reduced AIU's CWC requirements by approximately $9,000. AIU says it also accepts Mr. Kahle's treatment of interest expense on TFTN in the CWC analysis.

AIU does not take exception to Mr. Kahle's use of the Gross Lag methodology, if applied correctly. While it accepts the use of the Gross Lag methodology, AIU disagrees with Mr. Kahle's statement that the Net Lag methodology does not consider the amount of cash provided by ratepayers through base rates. AIU insists that the Net Lag methodology presumes that the operating expenses considered in the analysis are the same as the revenues available to pay such operating expenses; therefore, the Net Lag methodology inherently includes the consideration of revenues, but it does not reflect revenues on the exhibit. Staff, AIU claims, continues to have the misperception that only the Gross Lag methodology reflects revenues. AIU asserts that both methodologies reflect revenues but only the Gross Lag methodology actually shows the revenues on the exhibit.

AIU asserts that the revenues used by Mr. Kahle reflect the revenue requirement which Staff believes to be necessary to earn a fair return on AIU's assets and to pay its operating expenses. From this amount, under the Gross Lag methodology, AIU says the return on equity and all non-cash operating expenses are removed from the operating revenues. The residual revenues included in the CWC analyses under the Gross Lag methodology, AIU states, are the amount required to pay cash operating expenses.

AIU says the objective of the CWC analyses is to evaluate the timing differences between the receipt of revenues and payment of expenses. To accurately determine the CWC requirements, AIU insists that the revenues considered in the analyses must correspond to the expenses and vice versa. AIU asserts that the inclusion of expenses for which there is no corresponding revenue stream will produce results which do not

reflect the true CWC requirements of AIU. When employing the Gross Lag methodology, AIU says it is important to maintain a balance between the level of revenues and operating expenses considered in the analyses. AIU states that the level of revenues considered in the analyses should reflect only those funds which are available to pay actual cash operating expenses. AIU says a number of reductions are made from actual revenues to arrive at the amount which is truly available to pay actual operating expenses. Similarly, AIU claims the operating expenses considered in the CWC analyses should only include those operating expenses for which there is a corresponding revenue stream.

AIU claims that its application of the Gross Lag methodology maintains the balance between revenues and operating expenses because the revenues and operating expenses considered in the CWC analyses are equal. AIU asserts that the analyses set forth by Mr. Kahle, however, does not maintain the balance between revenues and operating expenses. According to AIU, Mr. Kahle inappropriately makes changes to the level of operating expenses (e.g., capitalized items) without a corresponding change to the revenue side of the equation. Under Mr. Kahle's approach, AIU claims the operating expenses have been artificially inflated thereby erroneously reducing AIU's CWC requirements.

AIU takes exception to Mr. Kahle's proposed treatment of pass-through taxes in calculating CWC requirements. Mr. Kahle proposes to include pass-through taxes in the CWC analyses, but to reflect a revenue lag associated with these taxes of zero days. AIU says Mr. Kahle assigns an expense lead of 42.79 days for the pass-through taxes. AIU claims the reduction of AIU's CWC requirements based upon Mr. Kahle's proposed adjustment to pass-through taxes is approximately $7 million.

According to AIU, Mr. Kahle's proposed treatment of pass-through taxes should be rejected because it has no foundation in reality. AIU says the revenue lag consists of five components; (1) a service lag; (2) a billing lag; (3) a collections lag; (4) a payment processing lag; and (5) a bank float lag. Collectively, AIU claims these components add up to the 40.95 days of revenue lag utilized by both Staff and AIU for purposes of determining AIU's CWC requirements. AIU states that the expense lead consists of three components; (1) a service lead; (2) a payment lead; and (3) a bank float lead. The expense lead used by both Staff and AIU was determined to be 42.79 days.

In AIU's view, it is appropriate to include pass-through taxes in the CWC analyses because there is a slight timing difference between AIU's receipt of payment from customers and the remittance of the taxes to the proper taxing authority. By including the pass-through taxes in the CWC analyses, AIU claims it is reflecting the benefit of having access to the funds from the time of receipt to the time of remittance.

According to AIU, Mr. Kahle's position is based on the incorrect premise that AIU has access to the funds associated with the pass-through taxes for 42.79 days. AIU contends that it collect the funds associated with the pass-through taxes when the

customers pay their bills. AIU maintains that there is no separate source of funds provided by the customers associated with the pass-through taxes.

Mr. Kahle, AIU avers, appears to suggest that there is no service lag associated with the pass-through taxes. AIU says that while that may be a reasonable position, there can not be a service lead on the expense side of the CWC calculation if there is no service lag on the revenue side of the equation. AIU claims Mr. Kahle's rebuttal position acknowledges this fact. Despite this modification, AIU asserts that Mr. Kahle's position continues to be flawed because it fails to reflect the true timing of cash receipts versus cash outlays. Despite Mr. Kahle's assertion to the contrary, AIU insists it does not have access to the funds attributable to the pass-through taxes during those days and claims that Mr. Kahle has provided no evidence to the contrary.

AIU also disputes Staff's assertion that pass-through taxes are not revenue. According to AIU, pass-through taxes are included in both revenues and expenses in the test year, before pro forma adjustments. AIU argues that it has provided service to customers, giving rise to the cost associated with pass-through taxes, and have to collect such monies from customers. Without the provision of service, AIU says there are no pass-through taxes.

If the Commission were to determine that there was no service lag/lead associated with the pass-through taxes, AIU says a revenue lag of 25.74 days should be applied to the appropriate level of revenues attributable to pass-through taxes and an expense lead of 27.58 days (i.e., 42.79 minus 15.21 days) should be applied to the expense levels associated with pass-through taxes. AIU states that this change would result in no change to AIU's CWC requirements. AIU also claims that the Commission previously declined to adopt the position proposed by Mr. Kahle. (AIU Initial Brief at 79-80, citing Docket Nos. 07-0241/07-0242 (Cons.), Order at 22)

AIU also takes exception to Mr. Kahle's proposed inclusion of capitalized payroll expenditures in the operating expenses used to calculate the CWC requirements. AIU indicates that Mr. Kahle proposes to include capitalized payroll in the CWC analyses by adding the amount of capitalized payroll to the operating expenses without a corresponding revenue stream. According to AIU, the impact of Mr. Kahle's proposed inclusion of capitalized payroll in the CWC analyses is to reduce AIU's CWC requirements by approximately $3 million.

Mr. Kahle, AIU states, tries to justify the use of this limited number of capitalized items in the calculation of the CWC requirements on the grounds that the Commission accepted a similar position in the last electric rate proceedings for AIU (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 36). AIU contends that Mr. Kahle, however, has provided no independent justification or rationale for the inclusion of the capitalized items in the CWC analyses, and, asserts that they should not be included at all.

AIU argues that Mr. Kahle has artificially created an imbalance by including in his analyses expenses for which there is no corresponding revenues, thereby resulting in a lower CWC requirement which is not indicative of the true CWC needs. AIU claims Mr. Kahle's inclusion of these capitalized costs is also inappropriate because his analyses represent only a partial view of capitalized expenditures. AIU claims it incurs significant levels of expenditures on an annual basis associated with capital programs and initiatives. AIU says Mr. Kahle's proposed treatment of capital expenditures does not reflect all of the capital expenditures and that he is selective in what items to include. Further, AIU asserts that Mr. Kahle has reflected an expenditure with significant dollars and relatively short expense lead time, artificially deflating the CWC requirements of AIU. In AIU's view, Staff's analyses reflect an incomplete view of capitalized expenditures and an artificially created imbalance between the revenues and operating expenses.

AIU says it has not included all of the capitalized expenditures in its CWC analyses. AIU claims its analyses reflect the actual cash operating expenses incurred during the test year. The capitalized amounts, AIU argues, are appropriately included in rate base and thus earn a return on such investments. AIU insists that it is inappropriate to include the capitalized expenditures in the CWC analyses. Regardless, AIU contends it would be inappropriate to include only a portion of the capitalized expenditures and only on one side of the revenue and expense equation. AIU maintains that the revenues which Mr. Kahle uses reflect the revenue requirement for the AIU. From those revenues, AIU says he appropriately subtracts non-cash expenses and return on equity. The residual revenues, AIU states, are those dollars which are available to pay cash operating expenses. AIU claims there are no incremental dollars in the analyses to account for the capitalized expenditures which Mr. Kahle proposes to include in the analyses. AIU concludes that Mr. Kahle has artificially created an imbalance between the levels of revenues and expenses considered in the analyses.

AIU is aware of only one solution that could remedy that imbalance: include in the CWC analyses a separate revenue stream relating to the amount of capitalized payroll. AIU says the revenue lag for this revenue stream would have to be the composite years over which AIU's assets are depreciated. AIU states that Mr. Adams, however, did not perform such a calculation because he does not agree with the inclusion of the capitalized expenditures in the CWC analyses. AIU, therefore, does not believe that an alternative to address Mr. Kahle's flawed recommendation is warranted.

Mr. Kahle believes it is appropriate to include the capitalized payroll in the CWC analyses because the test year is a historical test year and no portion of payroll after the effective date of the new rates is included in the rate base. AIU disagrees because the test year reflects a full twelve months of wages, reflected for known and measurable changes. AIU asserts that there is no need to reflect some level of payroll after the effective date of the new rates. AIU says Staff has not adjusted the expense level of wages to address this concern of Mr. Kahle's. AIU therefore concludes that there is no need to make such an adjustment for the CWC analyses.

AIU says it is true that it has not included capitalized payroll for the calendar year 2009 and claims it would be inappropriate to do so without a known and measurable capital adjustment with which the capitalized payroll is associated. According to AIU, Mr. Kahle's adjustment reaches beyond the 2006 test year to include 2009 capitalized payroll, which he assumes will be incurred at the 2006 historical level, and includes the presumed capitalized expenditure in an historical test year. AIU asserts that Staff has provided no evidence that the level of capitalized payroll in 2009 will be the same as it was in 2006. AIU says its level of capitalized payroll varies on an annual basis. Once the actual capitalized expenditures are incurred, AIU claims they will be reflected in AIU's rate base in the next rate proceeding. AIU insists that it would be inappropriate to include an unsubstantiated level of future capitalized payroll in these proceedings. AIU also disagrees with Staff that its proposal correctly reflects cash needs, since Staff has not provided a source of cash for the capitalized payroll cash outlay. If the Commission decides to include the capitalized expenditures, AIU maintains that a revenue stream must also be included in the CWC analyses.

AIU says that in rebuttal, Mr. Kahle argues that AIU witness Adams is wrong in asserting that a balance between revenue and expense level is required because the Commission's order in AIU's prior rate proceedings included adjustments to CWC which were based on analyses in which expenses were greater than revenues. AIU states that Mr. Kahle also argues that the inclusion of the capitalized portion of payroll expense in determining CWC requirements does not affect AIU's recovery of payroll costs.

According to AIU, Mr. Kahle's argument for his treatment of capitalized expenditures is based exclusively on the Commission's decision in AIU's last electric cases. AIU says it does not believe that a mistake should be repeated merely based upon past mistakes. AIU believes the appropriateness of the proposed adjustment should be evaluated based upon the merit of the arguments in the proceeding and not merely upon a prior Commission ruling. AIU maintains that Mr. Kahle's proposed adjustment is flawed, does not reflect the true CWC requirements of AIU, and should be rejected.

To the extent Commission precedent guides the Commission in this proceeding, AIU urges the Commission to focus on Docket Nos. 07-0241/0242 (Cons.). In that more recent proceeding, AIU says the Commission reversed its decision on this issue. AIU claims that Mr. Kahle dismisses that decision by claiming that the circumstances were different. In AIU's view, the circumstances in the two cases are not different; only the result was different and did not favor Staff's proposed adjustment.

Mr. Kahle has also proposed an adjustment to the CWC component of Rider PER - Purchased Electricity Recovery ("Rider PER"). AIU indicates that Mr. Kahle's calculation uses 23.94 expense lead days instead of the 18.15 days AIU proposes to use. AIU states that Mr. Kahle believes since AIU and Ameren Energy Marketing Company are affiliates, it is not reasonable to apply the shortened service period and advanced payment time to their transactions. AIU asserts that its current credit ranking has shortened the service period for purchased power to a half-month with payments

due on the first business day nine days following the end of the service period. AIU says Mr. Kahle does not contest the application of the shortened payment periods for non-affiliated companies, but proposes to disallow the shortened payment period for affiliated companies. Mr. Kahle contends that the shortened payment period does not apply to the affiliated companies because the funds for these purchases come from and end-up in the same pool of money.

Based upon Mr. Kahle's proposed adjustment, AIU says it appears that he believes that the dealings with affiliates should be handled differently than those with non-affiliated companies. Citing 83 Ill. Code 450, "Non-Discrimination in Affiliate Transactions for Electric Utilities" ("Part 450"), AIU claims the Commission's rules pertaining to transactions with affiliated marketing companies strictly forbid such unique treatment. AIU believes that providing payment terms which are different than those encountered between AIU and non-affiliated marketing companies would be contrary to the Commission's rules. AIU also argues that it and Ameren's marketing affiliates do not commingle funds as suggested by Mr. Kahle. AIU says each business operates as a stand-alone company and is responsible for its own financial transactions. AIU also claims that the source of the funds has no relevance on the timing of payment for transactions. The CWC component of Rider PER, AIU asserts, should reflect the actual timing of cash receipts and cash payments, not Mr. Kahle's assumed preferential treatment afforded to an affiliated marketing company.

AIU says that in rebuttal, Mr. Kahle argues that using the shortened service period for AIU's purchases from affiliates does not run afoul of Part 450 because it only prohibits preferential treatment, and his proposal does not provide preferential treatment. According to AIU, Mr. Kahle also argues that although AIU and Ameren Energy Marketing Company do not commingle funds, it is not logical that Ameren Energy Marketing Company would refuse to keep AIU as a customer if its payments were not advanced as allowed under the Supplier Forward Contracts.

According to AIU, the Commission has rules in place to protect against preferential treatment between affiliated companies. AIU claims Mr. Kahle is essentially proposing to bypass such safeguards. AIU asserts that Mr. Kahle makes an unsubstantiated assumption that the affiliated suppliers would even be willing to provide different payment terms for AIU. AIU contends that the non-affiliated providers could also choose to not seek advanced payments, but they did not. AIU believes it is unreasonable to assume that the affiliated providers would be more willing to waive the accelerated payments and assume additional risk without compensation. In AIU's view, these are the types of situations which the Commission's affiliate rules are intended to prevent. AIU concludes that Mr. Kahle's proposed adjustment to the CWC component of Rider PER should be rejected.

b. Staff's Position

Mr. Kahle proposes downward adjustments to the level of CWC to be included in rate base by the following amounts: $645,000 for AmerenIP's gas operations,

$1,563,000 for AmerenIP's electric operations, $668,000 for AmerenCIPS' gas operations, $1,060,000 for AmerenCIPS' electric operations, and $72,000 for AmerenCILCO's electric. He proposes an increase of $151,000 for AmerenCILCO's gas operations. To calculate his proposed CWC for AIU, Mr. Kahle proposes adjusting the lead days for Employee Benefits to 24.746 days due to an error in AIU's lead/lag workpapers related to Group Health Administration lead days. Staff indicates that AIU accepts Staff's adjustment for each of the utilities.

Mr. Kahle also proposes that the Gross Lag methodology be used in calculating CWC. AIU indicates that it is willing to accept the use of the Gross Lag methodology as long as the methodology is applied properly. Thus, Staff reports that the following CWC items are in dispute: capitalized payroll in CWC requirements; applying zero revenue lag days to pass-through taxes; and expense levels to which CWC factors are applied.

Mr. Kahle proposes to include total payroll in the CWC requirements, including the amounts capitalized as well as those charged directly to expense accounts in the CWC calculation, since all require cash. AIU argues that capitalized items are appropriately included in rate base, not in the CWC analyses. Staff contends, however, that capitalized payroll included in rate base does not include any payroll costs going forward. Staff believes the CWC necessary to cover payroll capitalized on an on-going basis when the rates from this proceeding go into effect are not included in rate base in this proceeding.

Staff asserts that processing and paying payroll is part of the AIU's day-to-day operations, that payroll to be paid in January 2009 is not in rate base in this proceeding and is outside the test year, and that AIU requires cash to meet its payroll in January of 2009. According to Staff, the circumstances in this proceeding are similar to the previous AIU rate case proceeding in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), in which the Commission found that the capitalized portion of payroll should be included in the CWC calculation. Staff believes that its proposal, which uses total base payroll in the CWC requirement calculation, correctly reflects cash needs of AIU and should be approved by the Commission rather than AIU's proposal which only considers payroll costs charged directly to salary and wages expense accounts.

In its Reply Brief, Staff claims AIU attempts to confuse the issue by implying that capitalized expenditures should not be included in the CWC requirement calculation because capitalized expenditures are included in rate base. Staff argues that expenditures, whether expensed or capitalized, are not, in themselves, recovered by adding the CWC requirement to rate base. Staff claims that only the financing of the expenditure is recovered by adding capitalized items to rate base. According to Staff, CWC is the amount of funds required from investors to finance the day-to-day operations of AIU. Adding CWC to rate base, Staff states, allows the investors to recover the time-value-of money associated with the cash outlay. Staff submits that including the capitalized portion of payroll expense in determining the CWC requirements only affects the amount of CWC requirement added to rate base for financing day-to-day operations of AIU, and does not affect the recovery of payroll

expense itself. Staff says AIU also advances an argument that revenues and expenses in the CWC requirement calculation must be equal. Staff contends this is not the case since the Commission has adopted CWC requirement calculations in which revenues and expenses are not equal. (Staff Reply Brief at 38-39, citing Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Appendix A, B and C at 6; Docket Nos. 07-0241/07-0242 (Cons.), Appendix A at 10 and Appendix B at 9) Staff also claims that in previous AIU rate proceedings, AIU has filed CWC requirement calculations in which revenues and expenses are not equal for AmerenCIPS gas and AmerenUE.

Mr. Kahle proposes to apply revenue lag days of zero to pass-through taxes. According to Staff, there is no revenue lag associated with pass-through taxes since pass-through taxes are not revenue. Staff asserts that AIU provided no service and did nothing to earn pass-through taxes. Staff claims investors have provided no investment related to the collection of pass-through taxes other than for operation and maintenance expenses already included elsewhere in the CWC calculation. Pass-through taxes, Staff says, are added on to the ratepayers' bills and then remitted to the appropriate taxing body. Staff contends that including a revenue lag for pass-through taxes in the CWC calculation would increase AIU's CWC requirement, and thereby increase rate base, allowing investors to earn a return on ratepayer supplied funding.

Staff states that ratepayers provide pass-through taxes for a taxing body with AIU having the use of these funds until AIU remits the taxes to the appropriate taxing body. Energy Assistance Charges, Staff states, are paid monthly by AIU on the 20th day following the month. AIU has use of these ratepayer provided funds from the time they are collected until the 20th of the following month plus bank float time, according to Staff. Gross Receipt Taxes, Staff adds, are paid monthly by AIU in the month following the month for which they are due. Staff says AIU has use of these ratepayer provided funds from the time they are collected until they are paid in the following month. Staff concludes that its proposal to use zero days for revenue lag correctly reflects that AIU has no cash requirements necessary to collect and remit pass-through taxes.

Mr. Kahle also proposes an adjustment to the CWC component of Rider PER to use 23.94 expense lead days instead of the 18.15 days that AIU proposes to use. AIU claims that Staff's logic is flawed and that it is reasonable to apply a shortened service period and advanced payment time in the transactions between AIU and Ameren Energy Marketing Company. Staff asserts that while AIU is referring to the affiliates' payment terms, Staff is referring to the calculation of the CWC component of Rider PER. Staff argues that its calculation affects Rider PER but not the actual power purchases from affiliates. Staff contends that using a greater number of expense lead days for the CWC component of Rider PER, which causes AIU to have a lower CWC requirement for purchased power, is not preferential treatment of an affiliate.

c. The AG's and CUB's Position

In addition to the CWC requirements based on the lead-lag studies, CUB says AIU increased the electric rate bases for each utility by an additional CWC allowance to

reflect a material increase in accounts receivable being experienced by AIU since the 2006 test year. According to CUB, the additional CWC increases the AmerenCILCO electric rate base by $3,478,000, the AmerenCIPS electric rate base by $6,406,000, and the AmerenIP electric rate base by $10,116,000. CUB says the increase applicable to each individual utility was calculated by allocating the total requested increase of $20 million in accounts receivable among the three utilities based on the number of electric distribution customers of each of the utilities. The $20 million total, CUB states, is based on an observed increase in the balance of accounts receivable in September 2007 over the level in prior years.

In CUB's view, there are several problems with the additional CWC increases proposed by AIU. CUB argues that AIU has not established that the observed increase in 2007 is permanent in nature. CUB also contends that an increase in accounts receivable by itself does not establish an increase in the CWC requirement. The CWC requirement, CUB says, is calculated as the cash needed to bridge the gap between the payment of expenses and the receipt of cash from customers to cover those expenses. To the extent that the increase in accounts receivable is the result of an increase in expenses, CUB claims the increase in receivables could well be matched by an increase in payables, resulting in no net increase to the CWC requirement. Based upon these concerns, AG/CUB witness Effron proposes that the additional CWC related to the increase in accounts receivable in 2007 be eliminated from AIU's electric rate bases.

d. Commission Conclusion

With regard to calculating CWC, the only remaining contested issues between Staff and AIU are whether capitalized payroll should be included in CWC requirements and whether it is appropriate to apply zero revenue lag days to pass-through taxes . The AG/CUB as well as Staff propose eliminating the additional CWC requirement associated with increased accounts receivable in 2007. In its rebuttal testimony, for purposes of the instant proceeding, AIU withdrew its proposal to increase CWC to reflect higher accounts receivable in 2007; thus, this issue is no longer contested. Finally, the Commission’s review of AIU’s and Staff’s Briefs on Exceptions and their Briefs in Reply to Exceptions reveals that the Proposed Order failed to include a conclusion regarding whether the expense lead days associated with purchase power transactions between Ameren Energy Marketing Company and AIU should be adjusted as Staff proposed. It appears the Proposed Order failed to reach a conclusion on this issue, in part, because Staff treated this as a contested rate base issue while AIU treated it as a resolved electric rate design/tariff issue. In any event, this issue will be addressed in this portion of the Order.

As the Commission understands it, Staff proposes to include capitalized payroll, as well as payroll expense, in the CWC calculation since Staff believes both types of payroll payments require cash. Staff believes the CWC necessary to cover payroll capitalized on an on-going basis when the rates from this proceeding go into effect are not included in rate base in this proceeding. Alternatively, AIU argues that capitalized items are appropriately included in rate base and not in the CWC analyses.

The Commission has reviewed the arguments of the parties as well as the previous decisions cited by the parties. Utilities acquire cash when ratepayers pay bills as well as through the issuance of debt and equity. The sources and uses of cash are comingled and can not be distinguished. The purpose of estimating a CWC requirement is to determine the level of funds required to meet a utility's day-to-day operations. By including CWC in rate base, the Commission allows a utility the opportunity to recover the cost of raising cash from its investors that is used in day to day operations. Capitalized costs, which are all paid with cash, are included in rate base so that a utility has an opportunity to recover the cost of financing that capital requirement item over time. In the Commission's view, if any capitalized cost, including capitalized payroll costs, were also reflected in the CWC balance, it would effectively be included in rate base twice. While it is true that cash is required to meet the requirements for payroll costs that are capitalized, the same is true for every other expense that is capitalized and the Commission can not understand the basis for singling out capitalized payroll costs. As a result, the Commission rejects Staff's proposed treatment of capitalized payroll costs when estimating the CWC requirement.

The Commission recognizes that Staff's proposed adjustment is consistent with the Order in the last AIU rate case; however, a review of that Order suggests AIU's failure to properly brief the issue in that case did little to help its position. Additionally, the Commission notes that the decision herein is consistent with the more recent decision in Docket Nos. 07-0241/07-0242 (Cons.), and believes the decision here is consistent with the record of this proceeding.

With respect to pass-through taxes, Staff proposes to apply zero revenue lag days arguing: that pass-through taxes are not revenue; that AIU provides no service and did nothing to earn pass-through taxes; and investors have provided no investment related to the collection of pass-through taxes. AIU believes pass-through taxes should be reflected in the CWC analysis due to the slight timing difference between AIU's receipt of payment and the remittance of tax revenue.

The Commission reviewed the arguments and, in the context of a CWC requirement, is unable to discern a meaningful difference between pass-through taxes and most other expenses. Customers pay their bills, including pass-through taxes, providing AIU with cash. AIU makes cash payments, including pass-through taxes, to those entities that have a rightful claim. Again, in the context of CWC requirement, pass-through taxes are no different than State or Federal income taxes or employee payroll expense. The Commission therefore concludes that Staff's proposed adjustment to the CWC requirement associated with pass-through taxes is inappropriate and is hereby rejected.

Staff proposes to adjust the expense lead days associated with purchase power transactions between Ameren Energy Marketing Company and AIU, but not the expense lead days between unaffiliated suppliers and AIU. Under Staff's proposal, Ameren Energy Marketing Company would be treated differently than unaffiliated power

and energy providers. These transactions are governed by supply contracts previously approved by the Commission, and the Commission finds Staff's proposal is inconsistent with the intent that all power and energy providers are to be treated the same. Staff's argument that it is simply proposing an adjustment to lower the CWC requirement but not the actual power purchases from Ameren Energy Marketing Company misses the point. This proposal would effectively deny AIU the opportunity to recover costs associated with supply contracts AIU entered into under Commission oversight. Such a proposal is not reasonable and is therefore rejected.

6. Physical Losses and Performance Variations

This issue concerns Accounts 352.3, "Nonrecoverable natural gas," and 823, "Gas losses," of the USOA for Gas Utilities. Account 352.3 provides in relevant part:

> A. This account shall include the cost of gas in underground reservoirs, including depleted gas or oil fields and other underground caverns or reservoirs used for the storage of gas which will not be recoverable.

Account 823 states in its entirety:

> This Account shall include the amounts of inventory adjustments representing the cost of gas lost or unaccounted for in underground storage operations due to cumulative inaccuracies of gas measurements or other causes. (See Paragraph G of Account 117, Gas stored underground – Noncurrent.) If however, any adjustment is substantial, the utility may, with approval of the Commission, amortize the amount of the adjustment to this Account over future operating periods.

a. Staff's Position

According to Staff witness Anderson, AIU's gas utilities attempt to treat every instance associated with storage field adjustments in the same manner, while there are actually distinctions in the types of storage adjustments. Mr. Anderson states that AIU's gas utilities are experiencing two different types of storage adjustments: physical losses and underground storage performance variations. Staff says physical losses refer to a known gas loss that can be attributed to a specific event at the storage field and occur as a result of the normal operation and maintenance of the storage field or even as a result of a leak within the storage field itself. Staff claims that underground storage field performance variation refers to changes in the storage field inventory, resulting in the need to add or subtract from the inventory at a storage field, which can not be attributed to a specific physical incident. Underground storage field performance variations, Staff states, are normally detected after an engineering evaluation by the deterioration of the performance of an underground storage field.

While not necessarily agreeing with Staff’s delineation of underground storage adjustments into two categories, Staff says AIU does not dispute Staff’s explanation or

description of the two categories. Instead, Staff says AIU maintains that both types of underground storage adjustments should be recorded in Account 823. In contrast, Staff witness Everson argues that performance variations are more properly recorded in Account 352.3 (rate base), and physical losses in Account 823 (expense). According to Staff, the contested issue here is the proper accounting treatment for AIU's performance variations.

Staff claims its proposal to place performance variations in Account 352.3 involves the basic mechanics associated with operating a storage field and that the majority of the performance variations result from gas migration. Specifically, Mr. Anderson states that natural gas is injected into an aquifer storage field above the pressure of the water in the aquifer. He says the natural gas injected will expand until the gas pressure and the water pressure reach equilibrium if there are no additional injections or withdrawals and a steady state is allowed to exist. In most aquifer storage fields, Staff says normal operation usually results in an average gas pressure above the aquifer pressure in the storage reservoir. As a result, Staff claims a small portion of the working or top gas tends to migrate to non-recoverable base gas over time, causing underground storage field inventory variations.

Mr. Anderson states that when gas is removed during the storage field's withdrawal cycle, the gas pressure within the field declines, allowing water to return to areas that had previously contained gas. According to Staff, each year, a utility injects gas that moves the water out, but the water returns when the utility withdraws the gas. Staff contends that because of this cycling of the storage field, a portion of the field's inventory also tends to migrate from working or top inventory to non-recoverable base gas.

AIU asserts that there are three major factors requiring the need for a utility to add gas to a storage field: (1) errors introduced over long periods of time through engineering calculations, (2) numerous gas losses that occur that are not estimated because they are unknown or are of a small magnitude, and (3) accumulated clerical and accounting errors, metering inaccuracies, and other operational/maintenance losses are the. Staff states that neither it nor AIU has been able to identify a method to quantify what components of performance variations are lost gas and what might migrate to non-recoverable base gas.

Staff believes that AIU accuses it of ignoring AIU's evaluation that uses the Tek Methodology, which AIU claims demonstrates that physical losses are occurring. The Tek Methodology is a gas loss calculation methodology presented in Appendix I of M. R. Tek's textbook, "Underground Storage of Natural Gas–Complete Design and Operational Procedures" ("Tek Methodology"). Staff says it is not ignoring AIU's evaluation; instead, Staff claims it is attempting to clarify AIU's analysis. Staff also disputes AIU's assertion that migration is not the major factor in the cause of or the need for performance variation adjustments. While Staff does not dispute that the three factors AIU identified can contribute, Staff argues that common sense suggests these are not the major factors causing performance variations.

Regarding the first factor, errors introduced over long periods of time, Staff states that since 2005 AIU has been making annual or nearly annual adjustments to all of its storage fields' inventory volumes. Staff also indicates that AmerenCILCO has made storage inventory adjustments since at least 1996, and passed those costs on to ratepayers. In Staff's view, there should not be any long-term accumulation of errors given the frequency with which the AIU makes storage adjustments.

Regarding the second factor, gas losses that occur that are not estimated because they are unknown or of small magnitude, Staff says that AmerenCIPS recorded physical losses as small as 136 million cubic feet ("Mcf") during the test year, while AmerenIP recorded losses as small as 26 Mcf. Staff argues that comparing the volumes of these physical losses, which AIU takes the time to identify and estimate to the magnitude of the annual adjustments (20,000-40,000 Mcf for AmerenCIPS; 3,445-228,102 Mcf for AmerenIP), demonstrates that any amounts that are too small for AIU to identify or estimate should be significantly less than the volumes AIU assigns to performance variations.

Regarding the third factor, accumulated clerical/accounting errors, metering inaccuracies, and other operational/maintenance losses, Staff asserts that clerical/accounting errors should be found and corrected if adequate controls are in place. Staff claims that meter accuracies are provided in a +/- 0.5 to 1% range. According to Staff, this means that metering could contribute or even reduce or create a negative loss of gas. Staff adds that AIU indicated, for at least its Hillsboro Storage Field metering, that its metering uncertainty is much less or about 0.25%. This demonstrates, Staff argues, that AIU has the means to reduce metering uncertainty. Staff believes metering errors should not be a major contributor to performance variations. Regarding other operational or maintenance losses, Staff maintains that AIU identifies and estimates fairly small gas losses and adds that AIU makes frequent annual inventory adjustments.

Staff argues that in a well-managed underground storage field operation, engineering estimates of physical gas losses should be reasonably accurate, unknown physical losses should be small, and metering errors should be determined and corrected as part of routine maintenance. Staff also contends that clerical/accounting errors should be found and corrected if adequate controls are in place. Staff says AIU has not demonstrated that any of these potential losses are significant or that the volumes associated with them would cause performance variations.

Staff claims that the need to significantly increase the non-recoverable base gas at AmerenCIPS' Sciota storage field is an indication that gas has been migrating on a regular basis in prior years. According to Staff, this is in direct contrast to AIU's position that all the annual adjustments at issue in this case are due to gas that has physically left the storage fields, and that migration is not causing these adjustments or migration is not occurring.

According to Staff, AIU complains about this being the first proceeding where it has been confronted with the concept of performance variations, and thus, has not had the opportunity to fully analyze the issue. However, Staff states that in Docket No. 02-0717, AmerenCILCO's 2002 purchased gas adjustment ("PGA") proceeding, not only did the Commission place AmerenCILCO on notice that at the earliest time possible it should treat and recover those storage adjustments as base rates, but Staff also indicated the proper accounting treatment would either be Account 352.3 or Account 823. (Staff Initial Brief at 75-76, citing Docket No. 02-0717, Order at 5) Staff also states that in Docket No. 03-0696, AmerenCIPS' 2003 PGA proceeding, wherein AmerenCIPS attempted to recover storage adjustments through the PGA, the Commission indicated that the costs in question are recoverable through base rates either through Account 352.3 or Account 823. (Id., citing Docket No. 03-0696, Order at 5) Despite AIU's protests in the instant proceeding, Staff claims the appropriate accounting treatment for its storage adjustments has been a concern between AIU and the Commission for some time.

AIU asserts that the amounts stated in the accounting of the losses should match the physical inventory amounts in the field. AIU is concerned that if the losses are continued to be accounted for as unrecoverable cushion gas, then the accounting numbers will eventually exceed what the field could physically hold as unrecoverable cushion gas. Staff contends that this is true only if AIU's view of how performance variations occur or what they represent is valid. Staff adds that if the accounting losses exceed what the field could physically hold as unrecoverable cushion gas, then AIU, after the appropriate engineering analysis, would have reason to request an alteration of how it accounts for its performance variations.

AIU cites the Order in Docket No. 04-0779, wherein the Commission allowed Nicor to recover in base rates costs that it had been recovering through its PGA clause as an operating expense. AIU claims that the Commission has approved recording gas storage losses of the type Mr. Anderson calls performance variations in Account 823. Staff, however, suggests it is unclear whether AIU's situation is the same as Nicor's based on the language in the Order in Docket No. 04-0779.

Staff states that in Docket Nos. 07-0241/07-0242 (Cons.), Peoples used 3.5% of injected volumes as additional base gas (base gas is accounted for in Account 352.3) to support Manlove Storage Field's performance. According to Staff, the Peoples witness stated that the gas in the Manlove reservoir is under pressure and tends to expand, radially invading new areas, and when this occurs some of the gas is inevitably trapped as cushion gas. (Staff Initial Brief at 77, citing Docket Nos. 07-0241/07-0242 (Cons.), Order at 105-106) Staff believes the discussion in the North Shore/Peoples Order supports Mr. Anderson's testimony regarding the existence and role of gas migration in performance variations.

Ms. Everson calculates an adjustment to reflect the proper accounting treatment of gas losses based on Mr. Anderson's testimony regarding the nature of the gas losses experienced by AIU. Staff states that losses that are not attributable to a specific cause

or incident can be characterized as storage field performance variations, and this gas, which is not expected to be recovered, should be classified as "non-recoverable base gas" and recorded in Account 352.3. According to Staff, Account 352.3 represents non-recoverable gas that can not be physically recovered when the field is abandoned and, therefore, amounts related to this gas loss should be capitalized and depreciated. Staff reports that none of the AIU gas utilities recorded losses in Account 352.3 from 1997 through 2006. Staff asserts that some of the variations AIU recorded in Account 823 were field performance variations and should be classified as non-recoverable gas and recorded in Account 352.3.

Ms. Everson also recommends that future gas losses should be recorded based on the nature of the loss. She says physical losses should be expensed in the period incurred in Account 823, while adjustments for underground storage field performance variations should be recorded in Account 352.3 and subject to depreciation. AIU responds that to properly adjust in this manner, gas losses identified as performance variations in other years would need to be adjusted from Account 823 to Account 352.3, and that such an adjustment would need to be made for performance variations that occurred within the last 10 years.

In response, Staff indicates that the adjustment to reclassify a portion of the 2006 test year cost of gas storage losses from Account 823 to Account 352.3 does not change their recoverability, only the manner in which they are recovered. Furthermore, Staff disagrees that amounts recorded to Account 823 in the past 10 years would have to be reclassified. Ms. Everson states that these adjustments will not require any other adjustments be made, to either the current rate case's rate base or AIU's books, for gas storage losses charged incorrectly to Account 823 in prior years. Staff says the gas storage losses from prior years have already been recovered by AIU through the rates charged during those years. According to Staff, to now reclassify and include those amounts in Account 352.3 would result in double-recovery, since the ratepayer has already paid for these costs through prior years' charges. In Staff's view, while the costs of prior years' performance variations should have been charged to Account 352.3 as well, the fact is they were not. Instead, Staff claims they have been completely recovered through the rates charged to ratepayers during those years, thus making the manner in which they should be recovered a moot issue.

Staff says that in surrebuttal testimony, AIU agrees that no reclassification of prior years' costs associated with AmerenCILCO's storage fields would be necessary. AIU maintains that a reclassification is needed for the prior years' costs associated with AmerenCIPS' and AmerenIP's storage fields. The basis for this assertion is that the amounts included in AmerenCIPS' and AmerenIP's last rate case for Account 823 expenses are not adequate to cover the charges made to this account in subsequent years. Staff believes AIU's reasoning is without merit. Staff argues that in the years between rate cases, the actual charges incurred for any expense has the potential to be less than or greater than the amount that was included for that expense in the last rate case. Staff describes this situation as regulatory lag. Staff claims such differences are not allowed to be considered in rate cases establishing the revenue requirement for

future periods. Assuming such a situation did exist with respect to Account 823 charges, Staff contends it was known by AIU at the time of the initial rate case filing and yet AIU made no attempt to include the shortfall in its revenue requests. Staff asserts that such actions would constitute retroactive ratemaking.

In its Reply Brief, Staff disputes AIU's suggestion that what Mr. Anderson would call migration to non-recoverable base gas can be recorded in Account 823, as it represents gas unaccounted for in underground storage operations due to other causes. Staff argues that if all storage adjustments, regardless of nature, could be properly recorded to Account 823, there would be no need for Account 352.3 to have ever been included in the Chart of Accounts. According to Staff, the reason why both Account 352.3 and Account 823 are necessary is to recognize the accounting difference between capital and expense items. Staff says Account 352.3 is a capital account and Account 823 is an expense account. Staff maintains that non-recoverable base gas is a capital cost. Staff insists that it would be a violation of accounting theory to charge such costs to an expense account as AIU advocates.

Staff also takes issue with AIU's statement that at the time of the last rate case these costs were not included in the base rates and therefore have not been collected. Staff says this statement refers to AmerenCILCO's storage field adjustments. According to Staff, the costs at issue here have been completely recovered through AmerenCILCO's PGA and, therefore, were not included in the base rates in AmerenCILCO's last rate case. To have done so, Staff argues, would have resulted in double recovery; first through base rates and then again in the PGA.

AIU points out that the AmerenCILCO's 2005-2007 PGA reconciliations are still pending a final Commission Order. Staff claims that, while this is technically true, AmerenCILCO has already recovered the costs for these years and would only have to return any amounts it collected for costs that may be deemed imprudent. (Staff Reply Brief at 46, citing 83 Ill. Adm. Code 525.70(b)) Staff says such an imprudence finding would still make AIU's reclassification argument moot since any costs found to be imprudent would not be allowed to be recovered through base rates either.

Staff argues that because there is no method for allocating between physical losses and migrating gas, the total amounts of performance variation adjustments must be charged entirely to either Account 352.3 or Account 823. Staff claims the costs can not be allocated even though they might contain elements of both physical losses and non-recoverable base gas. Staff asserts that as a result, neither account will be the perfect fit. The goal, in Staff's view, must be to use the account that most accurately reflects the true nature of the performance variations. Staff contends that this is Account 352.3 based on: (1) Mr. Anderson's arguments that the majority of performance variations are the result of gas that has migrated to non-recoverable base gas; (2) AIU's annual storage field inventory adjustments that reduce cumulative losses from inaccurate metering, small gas losses, and clerical errors, which in a well-maintained storage field operation should already be minimal; and (3) AIU's failure to show that the

gas losses associated with performance variations have physically left the storage fields.

b. AIU's Position

AIU provides four reasons why the Commission should reject Staff's proposal. AIU states that the language of Account 823 makes clear that "performance variations" are properly accounted for in Account 823. AIU asserts that Staff concedes that not all performance variations are in fact migrations to non-recoverable base gas, so transferring all "performance variations" from Account 823 to Account 352.3 is improper. AIU contends that the Commission has determined that gas losses are properly accounted for in Account 823. Finally, AIU claims transferring gas loss amount from Account 823 to Account 352.3 would require adjustments to rate base for the prior years.

AIU asserts that the language of Account 823 is broad, encompassing gas that is either lost or is otherwise unaccounted for due to cumulative inaccuracies of gas measurements or other causes. In AIU's view, an inventory adjustment for gas that is unaccounted for any cause is properly included in Account 823. AIU asserts that there is no requirement in the language of Account 823 requiring that lost gas recorded in that account relate to gas lost in a specific incident, or even that lost gas recorded in Account 823 be a "physical" loss of gas.

AIU claims that the types of "performance variations" Mr. Anderson refers to, such as errors introduced over long periods, losses that occur that are unknown or of small magnitude, and accumulated clerical errors, metering inaccuracies, and other operational/maintenance losses, are the exact "cumulative inaccuracies of gas measurements" that should be recorded in Account 823. AIU believes that even what Mr. Anderson would call migration to non-recoverable base gas can be recorded in Account 823, as it represents gas "unaccounted for in underground storage operations due to . . . other causes."

AIU asserts that Account 352.3 does not refer to the calculation or recording of gas losses. Account 352.3, AIU argues, refers to gas in the reservoir, so it is not an appropriate account in which to record lost gas. According to AIU, the gas described by Mr. Anderson as a performance variation is not in the field reservoir and so is lost. AIU claims it is incorrect to account for virtually all of the "lost" gas in Account 352.3, and Mr. Anderson's testimony does not support the wholesale transition of amounts in Account 823 to Account 352.3. In AIU's view, Mr. Anderson's performance variations are lost gas, and as such should be recorded in Account 823. AIU says that, although there may be an appropriate distinction between physical losses that can be estimated with engineering calculations and losses that can not be estimated, there is no basis for a different accounting treatment of measurable physical losses and other gas losses from a storage field.

AIU states that reservoirs can not hold an infinite volume of gas, and in its present form, AIU believes Staff's recommendation to continually transfer performance variations to non-recoverable base gas does not take into account the ability of the reservoir to hold these volumes of gas. AIU asserts that continually adding performance variation adjustments to the non-recoverable base would eventually cause the amount of gas recorded in Account 352.3 to exceed the capacity of the reservoir to hold gas, at least from an accounting standpoint. AIU also claims it would cause rate base related to the gas storage field to increase substantially over time.

AIU claims that some performance variations are physical losses of gas, and that not all performance variations represent migration to non-recoverable base gas. AIU further asserts that such physical losses could be recorded in Account 823. The fact that performance variations include physical losses and do not entirely consist of migration to base gas completely, AIU argues, undercuts the rationale for Staff's proposed shift to Account 352.3.

According to AIU, Staff's position is that some, but not all, of the performance field variations described by Mr. Anderson represent gas that has migrated to base gas and should be recorded as non-recoverable base gas. AIU says Staff admits that so-called performance variations can include physical losses of gas as well as gas migrating to non-recoverable base gas. AIU argues that if performance variations can include physical losses, then under Staff's logic, some performance variations are properly included in Account 823. AIU complains that Staff has not changed its recommendations regarding shifting gas losses to Account 352.3 and continues to recommend that all of the so-called performance variations be placed in Account 352.3. AIU avers that if it is possible that performance variation could include actual physical losses, then those performance variations should remain in Account 823.

AIU also complains that Staff does not quantify what part of performance variations are physical losses and what part is migration to non-recoverable base gas. Moreover, Staff agrees that such quantification is not feasible. In AIU's view, Staff established no basis for shifting the costs to Account 352.3, when accounting for such losses in Account 823 is reasonable and appropriate. AIU also claims that Staff has not explained why, if performance variations include physical losses, such losses would not be gas lost through "other causes." Theoretically, AIU states, some of the performance variation gas could migrate to base gas; however, AIU claims there is no known technique by which to separate performance variations into lost gas or non-recoverable base gas. AIU asserts that these migration losses would be very small in scale. AIU believes it is appropriate to include this gas loss as part of the annual gas loss adjustment in Account 823.

This proceeding, AIU asserts, is the first time AIU has been confronted with the concept of performance variations. AIU also says that the term "underground storage field performance variation" is not a term commonly used in the gas industry. AIU asserts that because the concept of performance variations is a new one, AIU has not had the opportunity to fully analyze it. AIU claims it has not been able to identify a

method whereby one could quantify the difference between various physical losses and losses of working inventory to non-recoverable base gas as a result of normal operations. AIU claims it is not aware of any methodology to quantify what components of performance variations are lost gas and what might migrate to non-recoverable base.

In Docket No. 04-0779, AIU says the Commission found that a withdrawal factor, representing gas losses, used by Nicor was appropriately included in Account 823 as an operating expense. (AIU Initial Brief at 223-224, citing Docket No. 04-0779, Order at 39-40) AIU says in that case, a Staff witness testified that expenses related to the operation of a storage field, including adjustments for inventory losses due to cumulative inaccuracies of gas measurements or other causes, should be recorded in Account 823. AIU asserts that even though a portion of the gas was for the replenishment of gas volumes that have become non-effective in contributing to the performance of the storage reservoir, the entire amount was charged to Account 823. The Commission ruling in the docket, AIU states, ultimately approved this treatment of the lost gas. According to AIU, the Commission has approved recording gas storage losses of the type Mr. Anderson calls performance variations in Account 823.

AIU complains that Staff's recommendation does not treat gas consistently from year to year. AIU says Staff suggests capitalizing certain gas losses for 2006, thus reducing AIU's test year expense and increasing rate base. If Staff's recommendation is followed, then AIU asserts like gas losses should be evaluated and capitalized as well, and become a part of rate base. AIU claims that taking what Mr. Anderson describes as performance variations and reclassifying them as non-recoverable base gas would, at present, result in increases to rate base.

Ms. Everson disagrees that adjustments to past year rate bases are needed. With respect to AmerenCILCO, Ms. Everson states that AmerenCILCO was recovering these costs through its PGA. At the time of the last rate case, AIU says these costs were not included in the base rates and therefore have not been collected. AIU states it is true that from the 2004 PGA reconciliation and before, the gas losses were collected ultimately through the PGA mechanism and the 2005-2007 reconciliations are still pending a final Commission order. AIU claims that as long as the gas loss costs continue to be collected through the PGA, AIU would agree that these costs should not be included in Account 352.3 for prior years. AIU contends that under Staff's proposal, if these costs are not included in the PGA, then the total sum of those losses from prior years 2005-2007 should be included in Account 352.3.

AIU states that AmerenCIPS (Docket No. 02-0798) and AmerenIP (Docket No. 04-0476) did submit certain gas loss expenses, related to estimated physical losses for discrete events, in Account 823 in their last rate cases. AIU asserts, however, that they did not submit any expenses related to performance variations as that term is currently defined by Mr. Anderson. Therefore, AIU claims there would not be any recovery from the ratepayers for those gas loss expenses and they would not be included in base rates. After the last rate cases, AIU says AmerenIP and AmerenCIPS began recording gas losses resulting from accumulated clerical and accounting errors, metering

inaccuracies, and other operational or maintenance losses (in addition to estimated physical losses related to discrete events) in Account 823. Thus, AIU states that the base rates for AmerenIP and AmerenCIPS reflect smaller amounts of gas loss expense than AmerenIP and AmerenCIPS are currently recording. According to AIU, Staff is now proposing that such gas losses should be prospectively recorded to rate base. AIU contends that under Staff's proposal, such costs should have been recorded to rate base in past years. If the Commission adopts Staff's proposal, AIU insists such past year gas loss costs should be transferred to rate base in this proceeding. Otherwise, AIU believes there would be a situation where the higher gas loss costs recorded to Account 823 since the last rate cases for AmerenIP and AmerenCIPS would not be recovered, since they are not presently in base rates and would not be placed in rate base under Staff's proposal in this case. AIU claims that the volumes shown in Mr. Underwood's rebuttal testimony for AmerenIP and AmerenCIPS represent volumes that should be reclassified as non-recoverable base gas if the Commission adopts Staff's proposal, resulting in the associated increases to rate base.

According to AIU, Staff argues that further evidence supporting Staff's position that migration is a major cause of performance variations is AmerenCIPS' adjustment to significantly increase the non-recoverable base gas at its Sciota storage field. AIU claims this position was not set forth in the testimony of any witness. AIU argues that, nevertheless, Staff's argument is without merit because AmerenCIPS' adjustment to increase the non-recoverable base gas at its Sciota storage field represents a determination that gas in the reservoir should be reclassified. AIU claims a detailed reservoir study, as well as a seismic study and a petrophysical review, was completed to specifically identify the amounts of gas in the Sciota field that should be adjusted to non-recoverable base. AIU contends that the results of this study determined how the volumes should be adjusted in that particular instance. AIU says this report, which was based on years of operating experience, new seismic studies of reservoir information, and reservoir simulations, enabled more accurate estimates of the volumes. In the case of performance variations, however, AIU says that it and Staff agree that there is no way to calculate what part of performance variations, if any, is migration to non-recoverable base. AIU insists that the fact that base gas in the reservoir at Sciota was reclassified to non-recoverable base says nothing about the proper accounting of lost gas. AIU also believes this reclassification says nothing about the proper accounting of lost gas, which Staff calls performance variations.

AIU also takes issue with Staff's assertion that transferring performance variations from Account 823 to Account 352.3 would be seamless from a cost recovery standpoint. AIU says Staff rejects AIU's position that the amounts in AmerenIP's and AmerenCIPS' current base rates do not reflect the full amount of expense that these two utilities now charge to Account 823. Staff argues that actual amount of an expense may be greater or less than the amount for which recovery is allowed in a prior rate case. AIU states that, while this is correct for an operating expense, Staff is proposing to switch performance variation amounts to a rate base account. AIU says that if performance variations are recorded in a rate base account, they represent an investment by the utility. AIU claims that, while its current filing recovers the full annual

amount of gas loss expense recorded to Account 823, a shift of that amount to rate base would leave prior years' investment stranded. AIU maintains that the base rates for AmerenIP and AmerenCIPS reflect smaller amounts of gas loss expense than AmerenIP and AmerenCIPS are currently recording.

According to AIU, Staff's reference to Dockets Nos. 02-0717 and 03-0396 as supporting the position that the gas loss accounting issue is nothing new are unavailing. AIU says those cases dealt with the question of whether gas losses should be recovered through the PGA or base rates. AIU claims the cases did not address which Account, 823 or 352.3, was the correct account to record such gas losses. AIU adds that they did not address the treatment of performance variations.

c. Commission Conclusion

Currently, AIU apparently records all gas losses in Account 823, which is an operating expense account. Staff proposes that AIU record all gas losses characterized by Mr. Anderson as performance variations in Account 352.3, which is a rate base account. While maintaining its position, AIU claims that if Staff's proposal were adopted, additional changes to rate base accounts for previous years would be required for AmerenCIPS and AmerenIP. Staff disagrees that any additional adjustments would be required.

Staff argues that the migration of gas to nonrecoverable natural gas is likely the primary cause of gas losses, although Staff does not know for sure what portion of gas losses have migrated. AIU does not go quite so far, although AIU does not seem to actually dispute the proposition that a portion of gas losses could easily be a result of gas migration. Instead, AIU relies on the broad language describing Account 823 and appears to suggest that any gas loss could be recorded in Account 823.

The record supports the accounting perspective that a portion of the gas losses should, in all likelihood, be recorded as a rate base item with the remainder recorded as an operating item. Because each of the extreme positions taken here seems likely to be improper, the Commission is faced with a rather difficult decision. The Commission finds the testimony of Mr. Anderson regarding the migration of gas to be the most convincing and, as a result, adopts Staff's proposed adjustments on this issue. The Commission finds that AIU should record gas losses for the test year in Account 352.3 as presented on Staff Schedules 14.04 G. In future rate cases, AIU is free to attempt to quantify the portion of gas losses resulting from the migration of gas and seek different accounting treatment of other gas losses.

Contrary to AIU's assertion, the Commission does not believe any additional adjustments for gas losses prior to the test year are necessary for AmerenCILCO, AmerenCIPS, or AmerenIP. To the extent amounts representing gas losses have been recorded in Account 823 and reflected in operating expenses in prior rate cases, no adjustments are necessary as the change ordered herein will be reflective of the test year and will be effective prospectively. To the extent gas losses have been recorded in

Account 823 and are reflected in AmerenCILCO's PGA reconciliations, as long as the gas losses receive appropriate treatment for the appropriate reconciliations, the utilities will be made whole. Additionally, the Commission directs AIU and Staff to make all reasonable efforts to ensure that gas losses are treated in a manner consistent with this decision for the outstanding 2005-2007 AmerenCILCO PGA reconciliations.

7. Working Capital Allowance for Gas in Storage

a. AIU's Position

AIU proposes that its working capital allowances for gas in storage be $53,023,000 for AmerenCILCO, $37,731,000 for AmerenCIPS, and $99,903,000 for AmerenIP. AIU understands that Staff proposes certain volume adjustments to the working capital allowance for gas in storage. In response, AIU indicates a willingness to accept Staff's proposal, and also proposes what AIU sees as the necessary counterpart adjustments. AIU asserts that if the Commission chooses to accept Staff's pro forma volume adjustments reflecting adjustments for normal weather and changes in leased storage contracts; the Commission should adopt AIU's proposed pro forma price adjustments.

AIU agrees in part that Staff's adjustments are acceptable, since there are new leased storage contracts in place and pro forma adjustments can be made for known and measurable changes. AIU submits that Staff witness Lounsberry's analysis on this issue contains only half of the necessary adjustments. According to AIU, if pro forma adjustments are made to the volume side of the equation, then the price side of the equation requires adjustment as well. Staff's adjustment, according to AIU, assumes that the per unit costs of the test year (2006) are valid in the year associated with Staff's pro forma inventory levels (2008); AIU argues this is not correct.

AIU submits that inventory costs in 2008 will not be equal to past years' costs. To reflect 2008 prices, AIU proposes what it calls a reliable proxy: the New York Mercantile Exchange ("NYMEX") natural gas futures price strip for the period April through October 2008, which it argues is the traditional injection season for all of the on-system and leased storage inventory. AIU avers that on April 8, 2008, that price was $10.00 per millions of British thermal units ("MMBtu") for the period. Mr. Lounsberry opposes AIU's pro forma adjustment to gas storage working capital to account for the significantly higher prices of natural gas in the calculation of inventory costs for three reasons: he believes that the 2008 prices are now known and measurable or determinable; he claims that AIU price hedge portions of its storage injection gas; and he believes that the 2006 per unit costs are in line with 2007 costs.

AIU asserts that with respect to Mr. Lounsberry's argument that 2008 prices are not known, measurable, or determinable, his own calculations are also predicated on projected (rather than known and measured) forecast volume data. AIU argues that Mr. Lounsberry is implying that the volume adjustments are also not known and measurable. AIU avers that Mr. Lounsberry's premise for his proposed volume

adjustments are two-fold; changes in AIU's leased storage levels and attempting to account for the warmer than normal weather realized during the 2006 test year. AIU argues that Mr. Lounsberry requested “expected” ending inventories “assuming” normal weather and utilized these as forecasted volumes instead of historical volumes that occurred during the test year. AIU submits that its request to reflect the forecasted cost of gas injected into its storage fields is no different than Mr. Lounsberry’s use of the forecasted ending storage volumes.

AIU contends that part of Mr. Lounsberry’s volume adjustment argument stems from his premise that 2006 was a warmer year than normal and that, for the test year 2006, AIU retained more gas in inventory than it would have in a year of normal weather. AIU submits that there are issues in addition to weather that are also important to the cycling of storage fields. AIU avers that it examined the ending inventories in AIU's storage fields, leased and owned on December 31, 2006, and the forecast inventories on December 31, 2008, and made known contractual changes. AIU argues that after this examination, it can not agree with Mr. Lounsberry’s volumetric adjustments associated with the difference between 2006 and 2008 weather, as Mr. Lounsberry has outlined a difference in degree days of approximately 10% between 2006 actual and 2008 normal. AIU submits that while such a difference may have a large impact on annual throughput and earnings from the utility’s perspective, it would not necessarily make a large difference in how the storage fields are operated. AIU further submits that the specific characteristics of each storage reservoir are another factor affecting the withdrawal plan.

AIU concurs with Mr. Lounsberry’s concern that its price hedge portion of the injection gas supply is not reflected in the proposed price adjustments. AIU points out that its risk management policy outlines a hedging strategy for up to 50% of its summer injection requirements. Therefore, AIU asserts it recalculated the projected storage Weighted Average Cost of Gas ("WACOG") for the pro forma test year. AIU submits that utilizing the utilities' hedged positions for the entire period of 2008 currently in place, actual storage inventories and prices through April 2008, and the NYMEX forward strip as of April 24, 2008, this calculation produces WACOGs of $8.79 to $9.00 per MMBtu. AIU avers that this result is reasonably comparable to the $10.00/MMBtu NYMEX strip used previously.

As a result of this analysis, AIU argues it has reduced its price adjustment on a per MMBtu basis, and the impacts that these revised WACOGs have on the storage working gas inventory balance result in AIU's current proposal for gas storage working capital allowance. AIU submits that it would be improper to allow a pro forma adjustment to be addressed on the volume side while ignoring the commodity price side. AIU avers that it is clear that the cost of AIU gas inventories on December 31, 2008, will be equal to or greater than at the end of 2006. AIU notes that in 2006, gas commodity prices at the Henry Hub averaged $6.74 per MMBtu; while through April 21, 2008, actual Henry Hub gas prices averaged $9.27 per MMBtu, a 37.5% increase over 2006. AIU avers that the NYMEX forward curve for the remainder of 2008 indicates an

average market price of $11.11 per MMBtu, reflecting a 65% increase over the 2006 cost levels.

AIU recommends that the Commission adopt the level of working gas inventory in the working capital adjustment that AIU filed in its direct cases. Should the Commission adopt Staff's pro forma volume adjustments, AIU submits that the Commission should further adopt AIU's pro forma price adjustments.

b. Staff's Position

Staff proposes an adjustment to reduce AIU's gas in storage inventory by the amount of accounts payable for the costs associated with the purchase of general materials and supplies and gas in storage inventory. Staff points out that AIU witness Wichmann states that AIU does not dispute the rationale for Staff witness Everson's adjustment regarding the accounts payable percentage, but does not agree with the value Mr. Lounsberry assigned to gas in storage.

Staff submits that its recommended alterations to amounts that AIU has requested for its working capital allowance for gas in storage are due to known and measurable changes in the gas volumes that AIU would maintain at its storage fields. Staff recommends changes to all of AIU's requested volumes due to the determination that AmerenCILCO and AmerenCIPS had known and measurable changes to their test year volumes, AmerenIP's test year volumes had changed and the 2006 test year was not a representative year. Staff points out that in order to calculate the adjustment, Mr. Lounsberry employed the same methodology that Staff used and the Commission accepted in the recent Peoples/North Shore rate cases on this issue, Docket Nos. 07-0241/07-0242 (Cons.).

For known changes, Mr. Lounsberry noted that AmerenCILCO's storage volumes were being increased due to increases in its Panhandle Eastern Pipe Line Company ("Panhandle") storage volumes effective April 1, 2006, as well as April 1, 2008. AmerenCIPS' storage volumes also changed by having its Panhandle contractual volumes decrease effective April 1, 2008, as well as decreased storage volumes from Texas Eastern Transmission Corporation as of July 1, 2006. Mr. Lounsberry further noted that AmerenIP had increased storage volumes from the Mississippi River Corporation as of May 16, 2006, increased the storage volumes received from Panhandle and ANR Pipeline Company as of April 1, 2006, and reduced storage volumes from Trunkline Gas Company as of April 1, 2006.

According to Staff, a warmer winter season makes it more difficult for a utility to withdraw gas storage volumes from its owned and leased storage fields, and that warmer weather, in general, creates a situation where more gas remains in the field than the utility had planned. Staff submits that since a utility's working capital allowance is based upon the volumes of gas remaining in storage, this means that a utility's working capital allowance for gas in storage in a warmer than normal year is higher than if it was based upon a year with normal temperature conditions.

Given Staff's concern's, Mr. Lounsberry calculated AIU's storage volumes using a normal 2008 year. Staff asserts this methodology ensures that AIU's storage volumes are normalized, rather than relying on historical storage volumes that are often impacted by temperature conditions that vary from the norm, and also accounts for the known and measurable changes that the AIU made to its storage volumes. Staff submits that Mr. Lounsberry's calculations were based upon AIU's projection of the storage volumes it would maintain in 2008 under the assumption a normal year occurred.

Staff recommends that the Commission adopt its suggested changes and set working capital allowances of $45,089,000 for AmerenCILCO, $32,259,000 for AmerenCIPS, and $82,396,000 for AmerenIP.

c. CUB's Position

CUB argues that a vast majority of storage gas is injected during non-winter months, and therefore there is a lag between when a utility injects the gas into a storage field or leased storage service (and pays its supplier for that gas) and when the utility withdraws that gas and receives its payment for the same gas. CUB proposes that AIU revise its requested working capital amounts to account for known changes of its gas in storage and to account for the normal temperature conditions.

AIU, according to CUB, did not properly account for the inherent lag between injection and withdrawal in gas storage, and therefore, the Commission should rely upon Mr. Lounsberry's recommendations that AmerenCILCO decrease its requested amount by approximately $4,359,000, that AmerenCIPS reduce its requested amount by approximately $13,669,000 and that AmerenIP reduce its requested amount by approximately $5,105,000.

d. Commission Conclusion

Staff proposes an adjustment to reduce AIU's gas in storage inventory by the amount of accounts payable for the costs associated with the purchase of general materials and supplies and gas in storage inventory. Staff submits that its recommended alterations to amounts that AIU requested for its working capital allowance for gas in storage are due to known and measurable changes in the gas volumes that AIU would maintain at its storage fields.

AIU agreed in part that Staff's adjustments are acceptable, since there are new leased storage contracts in place and pro forma adjustments can be made for known and measurable changes. According to AIU, if pro forma adjustments are made to the volume side of the equation, then the price side of the equation requires adjustment as well. AIU submits that inventory costs in 2008 will not be equal to past years' costs. To reflect 2008 prices, AIU proposes what it calls a reliable proxy: the NYMEX natural gas futures price strip for the period April through October 2008, which it argues is the traditional injection season for all of the on-system and leased storage inventory. AIU

avers that on April 8, 2008, that price was $10.00 per MMBtu for the period, which was subsequently adjusted in an effort to reflect the fact that AIU hedges portions of the injection gas supply. AIU submits that it would be improper to allow a pro forma adjustment to be addressed on the volume side while ignoring the commodity price side.

CUB argues that a vast majority of storage gas is injected during non-winter months, and therefore there is a lag between when a utility injects the gas into a storage field or leased storage service (and pays its supplier for that gas) and when the utility withdraws that gas and receives its payment for the same gas. CUB proposes that AIU revise its requested working capital amounts to account for known changes of its gas in storage and to account for the normal temperature conditions. According to CUB, AIU did not properly account for the inherent lag between injection and withdrawal in gas storage, and therefore, the Commission should rely upon Mr. Lounsberry's recommendations.

The Commission finds Staff's proposal to make pro forma adjustments to the working capital allowance to reflect revisions in storage volumes to be reasonable and it is hereby approved. The Commission believes that these adjustments will better reflect AIU's cost structure that will be in place when rates established in this proceeding take place. While Staff objects to AIU's proposal to make adjustments to the price associated with gas in storage, the Commission believes it appropriate. AIU made an adjustment to the proposed price to reflect the fact that it hedges a portion of the gas injected into storage in direct response to Staff's concern. Contrary to Staff's suggestion, the use of NYMEX natural futures contracts is not unheard of in establishing rates. The Commission concludes that in this instance, the price proposal of AIU is reasonable when used in conjunction with Staff's proposed quantities of gas.

As for CUB's proposal, the Commission has established the appropriate CWC allowance elsewhere in this Order and believes there is no point in addressing the issue here.

8. Hillsboro Base Gas Inventory Valuation (Prior Adjustment)

a. AIU's Position

AmerenIP seeks to include in rate base $10,367,838 associated with base gas inventory at the Hillsboro Storage Field. In doing so, AIU is essentially asking the Commission to revisit its decision in Docket No. 04-0476 disallowing this amount. Even though an appellate court upheld the Commission's disallowance, AIU argues that circumstances have changed since Docket No. 04-0476. AIU wants the Commission to consider the fact that the Hillsboro Storage Field has now been restored to its full "used and useful" levels for peak deliverability to system sales customers, which was not the case in the previous proceedings. AIU argues that it is not just the Hillsboro field that is used and useful, the $10,367,838 cushion gas amount is also used and useful. AIU

claims that AmerenIP is not currently being allowed to earn a return on assets that are used and useful, prudently incurred, and providing full benefits to its customers.

Gas storage operations, AIU argues, benefit its gas customers. According to AIU, system storage provides flexibility and reliability for gas supply to customers that can not be found elsewhere for the same value. AIU says this flexibility on the natural gas system allows for the efficient balancing of supplies and usage. AIU adds that the storage fields provide reliability by being a source of gas supply close to the customers, therefore reducing risk related to facility failure or disruption to the supply of gas.

AIU contends that on-system storage also generates financial benefits for gas customers, by lowering the price of gas. When combined, AIU indicates that the peak day deliverability of AmerenCILCO, AmerenCIPS, and AmerenIP, is 1,182,264 MMBtu, with a storage delivery of 578,759 MMBtu (48% of the peak day send out of the combined utilities). AIU asserts that replacing the storage deliverability of AmerenIP with interstate pipeline deliverability would increase the PGA costs by almost $100 million a year, not including any seasonal differential associated with the commodity purchases. In AIU's view, gas storage provides ratepayer benefits, and AmerenIP should be allowed to recover its reasonable and prudent expenses related to gas storage field operation, including the Hillsboro Storage Field base gas inventory.

In Docket No. 04-0476, the Commission addressed a situation in which AmerenIP had withdrawn cushion gas from the Hillsboro field due to a metering error. As a result of the over-withdrawals from the field, AmerenIP had to replace the withdrawn cushion gas with gas purchased at higher prices than the historical cost of the cushion gas reflected in rate base in Illinois Power's 1993 rate case. The Commission agreed with the Staff, and concluded that the excess of the replacement cost over the historical cost of the cushion gas could not be recovered until the gas is withdrawn from the field at the end of the field's useful life, and that AmerenIP could not earn a return on the excess cost in the interim.

AIU claims that the effect of the decision imposes a penalty on AmerenIP out of proportion to the effect on customers. AIU claims the error provided lower cost gas to customers than they otherwise would have received. AIU states that AmerenIP must bear the financing costs of a portion of its cushion gas for the remaining useful life of the field, which could be 30 years or more. From AIU's perspective, customers receive the double benefit of both the consumed lower priced gas withdrawn from the field and the historical cost of the cushion gas for the remaining life of the field. AIU claims it will essentially lose its investment in the additional costs of the replacement gas. By the time AmerenIP obtains any recovery of the investment, AIU complains that it will have incurred financing costs far in excess of its investment.

AIU proposes at least two ways to address this situation. One is to reflect the full value of the cushion gas in rate base in this proceeding. AIU maintains that customers have benefited both from the lower cost gas through the PGA and avoided financing costs on the additional investment for three years. AIU believes the lost financing cost

over those three years is an adequate revenue impact for AmerenIP, especially since the field has been returned to its full used and useful status. Alternatively, AIU suggests that the Commission could allow it to recover the excess cost, which AIU claims is roughly the cost customers should have paid through the PGA, in this case. AIU says that under this approach, customers avoid several years of financing costs, the inventory is priced going forward as though the metering error were never made, and at the end of the useful life of the field customers will receive even lower priced gas.

AIU also asserts that the management concerns at Hillsboro raised in Docket No. 04-0476 have been addressed. AIU states that Staff witness Lounsberry acknowledges that most of the problems he identifies related to the Hillsboro Storage Field existed prior to 2004, that he has not seen a reoccurrence of those problems, and that he is aware of improvements made in “management oversight” of gas storage at AmerenIP since December 2000. Since 2004, AIU explains that several significant organizational changes and improvements have been made to improve gas operations, which emphasized the importance of the gas storage operations at AmerenIP's gas facilities, and provided continued value to its customers. AIU asserts that improvements have also been made to the operations of the gas storage fields, including concentration on the metering area. AIU notes that new ultrasonic metering installations were performed at Ashmore in 2005, Tilden and Hillsboro in 2006, and Shanghai in 2007, and there are plans to install new metering facilities at Hookdale and Freeburg in 2008. These improvements, AIU asserts, make higher levels of operation performance possible through the availability of better equipment.

According to AIU, several recently-completed capital projects have also contributed to improvements in AmerenIP’s operations. AIU states that $3.1 million in capital expenditures were made in 2006, and over $7 million of capital expenditures were made in 2007, all related to improving performance at gas storage fields. AIU relates that some of the larger projects include the previously mentioned facility metering projects, water disposal system, hydrogen sulfide ("H_2S") removal facilities, replacing motor control centers, adding gas chromatographs, and replacing a glycol regenerator. AIU claims that these improvements and changes have had a measurable impact on gas storage field performance since 2004. AIU notes that for all AmerenIP gas storage fields, including Hillsboro, there has been no increase or decrease of peak day ratings. Overall, AIU claims that the fields have been performing well and have provided value to the ratepayers, without the storage field customers having to pay more in PGA costs.

In its Reply Brief, AIU states that in Docket No. 04-0476, Staff viewed the disallowance in part as a penalty for poor management at Hillsboro. AIU observes that Staff acknowledges there have been numerous improvements and investments at Hillsboro since 2004. As a result, AIU argues that the past problems do not persist and do not represent present concerns. According to AIU, the concerns about Hillsboro that Staff raised in Docket No. 04-0476 in recommending the disallowance of the $10,367,838 amount have been addressed. In AIU's view, because AIU addressed these concerns, the rationale for penalizing AmerenIP for its poor management at

Hillsboro has been eliminated, and the $10,367,838 disallowance should be reconsidered.

b. Staff's Position

Staff objects to AIU's request to revisit the issue of revaluing a portion of the Hillsboro Storage Field's base gas inventory. Staff says AIU requested the Commission's permission to increase the value of its recoverable base gas inventory at Hillsboro by $10,367,838 in Docket No. 04-0476, AmerenIP's last gas rate case. AmerenIP's basis for that previous request, Staff states, was that it experienced a significant gas measurement error at its Hillsboro field during the period November 1993 through October 1999. AmerenIP estimated that the impact due to the measurement errors caused its measurement records to overstate its actual gas inventory by 5.8 billion cubic feet ("Bcf"). AmerenIP also claimed that, as a result of the measurement error, it withdrew gas from the Hillsboro field in excess of those levels that it maintained in its top gas volumes, and withdrew gas from its recoverable base gas inventory. According to AmerenIP, the impact of this activity was that it withdrew recoverable base gas that was lower-priced than the gas it had placed in the field during the injection season, resulting in AmerenIP's request to increase the value of its recoverable base gas inventory at Hillsboro by $10,367,838.

Regarding AIU's primary proposal, to include the cost of gas in rate base, Staff says this methodology was fully discussed and argued before the Commission in AmerenIP's last rate case. At that time, the Commission agreed with Staff and denied AmerenIP's request to revalue the base gas inventory at Hillsboro. Staff notes that AmerenIP appealed the Commission's decision to deny its request to revalue the base gas inventory at Hillsboro, and on October 2, 2006, the appellate court affirmed the Commission's decision. In Staff's view, AIU did not provided any new arguments or information in this proceeding for the Commission to consider that would support a change in the Commission's prior decision.

With regard to AIU's secondary proposal to create a regulatory asset and amortize it over two years, Staff argues this would provide no benefit to ratepayers in that it would essentially allow AmerenIP to expense an item that would normally be a rate base item. Staff claims AIU's proposal would only provide a benefit to AmerenIP without a corresponding benefit to its ratepayers. AIU claims that it was not attempting to reverse the Commission's prior decision in AmerenIP's last rate case or to prove the Commission wrong. Instead, AIU indicates that it is asking Staff to give new consideration and weight to the fact that the Hillsboro field has been restored to its full "used and useful" levels for peak deliverability to system sales customers and that the full amount of the cushion gas is being used to provide that full "used and useful" level of peak deliverability. According to Staff, AIU is advocating a reversal of the Commission's prior Order. The Commission's Order on this issue in Docket No. 04-0476 not only provided a conclusion on this issue, but also clearly directed the manner in which AmerenIP would recover its costs in the future. Staff says the cost will

ultimately be recovered through the PGA clause when the gas is withdrawn and delivered to PGA customers.

Staff claims that AIU's only basis for reversing the Commission's prior decision is that the Hillsboro field is now fully "used and useful" and it provides peak deliverability. According to Staff, the Commission's Order in Docket No. 04-0476 clearly provides a separate discussion and conclusion regarding the issue of the inventory revaluation, versus the used and useful discussion and conclusion. Staff also contends that AIU is in error to claim that the Hillsboro field was not at peak deliverability during AmerenIP's last rate case. Staff says the Commission's Order clearly indicates that IP had restored the peak day deliverability rating of the Hillsboro field to its design level prior to the 2003-2004 winter season, which is prior to AmerenIP's rate case filing in Docket No. 04-0476. In Staff's view, AIU presented no basis for a reversal of the Commission's prior decision in Docket No. 04-0476. Staff recommends that the Commission deny AIU's request to revalue the Hillsboro field's base gas inventory by $10,367,838, or, in the alternative, to account for this value in another manner.

c. Commission Conclusion

Despite AIU's protests, it appears to the Commission that the circumstances here are identical to those present in Docket No. 04-0476. In that case, the Commission rejected AmerenIP's proposal to include in rate base the additional base gas at Hillsboro, which is the request AIU repeats here. The Commission previously decided this question, this decision was affirmed by the appellate court, and the Commission can discern no change in facts or circumstances that warrant revisiting or reconsidering the question here. AIU's proposal is rejected.

9. Hillsboro Base Gas Inventory Valuation (New Adjustment)

a. AIU's Position

AmerenIP proposes to add $2,841,000 to the Hillsboro base gas account, an increase in rate base. AIU claims that the addition is necessary to account for base gas lost through a valve leak. According to AIU, the added volume represents gas that is now used and useful in providing service to customers, and the cost of the added gas has been prudently incurred.

AIU states that tests on newly-installed ultrasonic gas meters at Hillsboro in January 2007 revealed that base gas volumes at Hillsboro must be adjusted. After the installation was completed, AIU says comparisons were made between the flow through the existing metering and the new metering. After analyzing the data, AmerenIP indicates it determined that 1,109,964 Mcf of additional gas was actually withdrawn but not reflected as withdrawals from the field from 2001-2007. AmerenIP says it replaced this 1,109,986 Mcf of gas by the end of the 2007 injection season, resulting in an adjustment of an additional $2,841,000 to the Hillsboro base gas account.

AmerenIP determined that there was a valve leak in the old metering equipment, which allowed gas to pass undetected and unmeasured through the secondary meeting run, over the period 2000 to 2007. AmerenIP says this resulted in a portion of base gas being withdrawn during the years 2001 to 2004, which was delivered to AmerenIP's sales customers. This base gas was replaced during the next injection season after the gas was withdrawn. AIU asserts that the replacement was required in order to meet the supply requirements of AmerenIP's gas customers because the proper operation of the storage field requires that the base gas be present to provide pressure support for the field. To assure the field can cycle 7.6 Bcf and peak at 125,000 Mcf/day, AIU explains that the field must have the established level of base gas and working gas. According to AIU, this is an investment that was required to meet the needs and requirements of AmerenIP's customers. AIU believes that the gas loss at Hillsboro was justifiably re-injected into the reservoir.

AIU argues that it is in the best interest of the ratepayers and AmerenIP to make regular adjustment for gas losses. Deferring an annual adjustment until ironclad support of a shortfall in inventory is in hand, AIU avers, could potentially cause a storage field to fall short of its delivery target, due to the cumulative effect of not making annual adjustments. AIU claims a shortfall in storage field gas could cause it to buy spot-market gas or overrun a pipeline contract to make up the shortfall. AIU says this would be an additional expense to ratepayers. AIU asserts that if it does not make timely additions to inventory it is possible that at some time in the future it will need to add a relatively large amount of gas to make up for the cumulative shortfall. AIU contends that this gas, in all likelihood, would be more costly than an annual addition of smaller amounts of gas.

AIU reports that Staff witness Lounsberry recommends disallowance of the $2,841,000 addition to the Hillsboro base gas account. Mr. Lounsberry originally set forth four reasons for disallowing this request to increase its recoverable base gas costs. Mr. Lounsberry argued that: (1) he does not consider AmerenIP's logic in determining the timing of the metering error at Hillsboro during the years 2001–2004 as valid; (2) AmerenIP has inadequate support for the assigned value; (3) he questions the validity of certain assumptions that AmerenIP made as part of the calculation; and (4) he states that, given the purported history of problems at Hillsboro, he would have expected AmerenIP to have conducted a review of the integrity of the valve at a much sooner date.

Mr. Lounsberry argues that it was not reasonable to assume that the valve leak in question began in 2000. AIU responds that while the start date of the valve leak is uncertain, AmerenIP selected 2000 as an estimate for the start date because that was the half-way point between when the valve was rebuilt (1993) and when the leak was discovered. AIU believes use of the halfway point is also reasonable because the 5.8 Bcf correction that the 2004 Hillsboro Study recommended would have accounted for all metering errors, including withdraw metering errors, up to 2000 only. AIU states that after 2000, as a result of AmerenIP's 1999 Meter Study (Peterson), the method of operating the storage field changed so that injection meter error was eliminated. AIU

adds that only data from the 1994 to 1999 time period was modified in the reservoir simulator's data deck to determine that the inventory shortfall was 5.8 Bcf. Injection data from 2000 to 2003 was accepted at face value, AIU says. Hence, AIU claims the impact of the valve leak metering error had already been corrected for the period up to 2000, and need only be accounted for thereafter.

Mr. Lounsberry's second concern is that AIU has not sufficiently supported the $2,481,000 assigned value of the base gas cost. Mr. Lounsberry cites two bases for his position: AmerenIP's inconsistent operation of Hillsboro makes it unreasonable to rely on reservoir data, and AIU's current proposal conflicts with data reviewed in a prior rate case. AIU asserts that no party challenged the two forms of input data in the data plot that AmerenIP uses to support the measurement error correction. AIU says the first data input is gas volume data, which are from the new ultrasonic metering, not the old plant metering, and therefore are considered to be accurate. AIU indicates that the second data input is pressure data, which are measurements of the wellhead pressure from the Truitt #1 pressure observation well. According to AIU, at no time has Mr. Lounsberry questioned the validity of this wellhead pressure measurement. AIU states that while Mr. Lounsberry asserts that AmerenIP may have employed other "superior" methodologies in past rate cases, AmerenIP used valid reservoir engineering techniques to determine gas loss. AIU argues that it is not required to use any one particular type of study to demonstrate prudence. (AIU Initial Brief at 108-109, citing Illinois Power Co. v. Illinois Commerce Comm'n., 339 Ill. App. 3d 425, 439 (5th Dist. 2003) ("Section 9-220(a) of the Act does not set forth any specific type of analysis that a utility must perform to show that its costs are prudent.")

AIU agrees that the reservoir model would be an appropriate method to determine gas losses; however, AIU says the reservoir simulator was not used to evaluate Hillsboro because the model data deck had not been updated to include the withdrawal metering corrections. Further, AIU claims techniques such as hysteresis curves and reservoir simulation techniques are not viable at Hillsboro at this point in time due to the present state of the data (in the case of the simulator), and the variation in gas volumes cycled (in the case of hysteresis curve analysis). AIU asserts that it used the best data available in its calculations. AIU maintains that the data available are sufficient to allow the base gas adjustment to be calculated based on sound engineering judgment. AIU states that as gas is injected and withdrawn from a reservoir, wellhead pressure will vary. AIU says this change in pressure can be, and is, utilized by AmerenIP to monitor reservoir performance via multiple techniques such as reservoir simulation, hysteresis curve analysis, the Tek Methodology procedure, and many other techniques. AmerenIP says it utilizes this information at all of its fields in one form or another as part of its ongoing inventory verification process. AIU concludes there is no basis to believe that the result of these two sources of data is in any way unreliable.

AIU asserts that Mr. Lounsberry ignores the results of the 2007 Hillsboro inventory adjustment. In 2006, when the 2006 Gas Loss Adjustment Report was written, AIU says it believed that the hysteresis curve analysis, modeling, and neutron

log evaluation for Hillsboro were, in fact, affected by the injection of additional gas into the field. But AIU claims that it also recognizes that gas losses are occurring on an ongoing basis in gas storage fields. In light of this fact, AmerenIP decided to inject 200,000 Mcf in order to begin addressing the known shortfall. AmerenIP states that 200,000 Mcf is 2.5% of the working gas volume in Hillsboro, which it claims is within the typical range for gas losses by Illinois gas utilities. Further, AIU claims it was able to confirm in 2007 that 200,000 Mcf was a conservative and reasonable estimate to use to address gas losses in the reservoir.

Staff's view that AIU's current proposal conflicts with data reviewed in a prior rate case is also incorrect, AIU argues. Staff believes that the 5.8 Bcf adjustment contained in the 2004 Hillsboro Report overlaps with the 1.1 Bcf adjustment under instant review. However, AIU asserts that the metering errors described in the 2004 gas rate case were corrected in the fall of 1999. AIU says the inventory correction volume of 5.8 Bcf quantified the effects of the accumulated metering errors from 1993 to 1999 and was reinjected into Hillsboro in 2004 and 2005. After 2000, as a result of Peterson's 1999 Metering Study, AIU claims the method of operating the storage field changed so that injection meter error was eliminated. Therefore, for modeling purposes and to allocate the 5.8 Bcf correction back in time, AIU maintains that only data from the 1994 to 1999 injection seasons were modified in the database. AIU says the analysis of the metering error that AmerenIP performed in 2007 after comparing the newly installed ultrasonic meters to the existing metering led AmerenIP to conclude that the leaking valve induced error began during 2000. AIU insists that the 1.1 Bcf correction was only applied beginning with the 2000 to 2001 withdraw season and ending with the 2006 to 2007 withdraw season. AIU maintains that there is no overlap of the requested adjustments, as this case requests inventory corrections for the period 2000 to 2003. At Hillsboro, AIU relates that an adequate stable inject and withdraw history dataset has not been established that would allow a detailed analysis utilizing hysteresis techniques. However, AIU believes other information is available to support the proposed inventory adjustment.

AIU avers that Mr. Lounsberry's third concern, that certain assumptions within AmerenIP's calculations are not robust, is also unfounded. AIU says Mr. Lounsberry laid out 5 specific concerns with the gas-volume calculation:

1. Valve leakage could have worsened over time.
2. Other errors could have caused the differences.
3. The 2.75 % error was used even when valve was fully opened.
4. Concern about only using the January 24 to February 25 time period and then extrapolating over 7 years.
5. All meters in series will show a percent difference.

AIU claims it has addressed all five concerns. AIU says the first concern makes a faulty implicit assumption: that the valve leak had worsened over time, and that the calculation thus overstated initial volumes that were not measured. AIU says it has no indication that the leak did worsen over time. Therefore, AIU concludes the 2000 start

point for the full leak is an appropriate assumption. In addition, AIU asserts that it would be difficult to identify when or at what rate such worsening of the leak would occur.

AIU claims the second concern, that there are other potential causes for the observed measurement error/gas-volume discrepancy, is unsubstantiated. Staff suggests that AmerenIP assumed that all of the errors it found were either caused by the leaking valve or the incorrectly installed orifice plate. AmerenIP says that although it can not determine that "all" of the errors observed were either caused by the leaking valve or due to the orifice plates, AmerenIP reasonably believes that the leaking valve or the orifice plates were the dominant sources for the observed errors. Staff further suggests that the metering review was incomplete, but AIU says it offers no specifics as to what should have been reviewed.

According to AIU, there is no justification for Mr. Lounsberry's position that the reference to volumetric variance resulting from pressure and temperature variance "confirms" the possibility of "significant" variances in measured values. AIU says the differences described for the temperature and pressure transmitters were from the period that comparison testing was conducted using the new ultrasonic meters and in-place South Pipeline ("SPL") orifice metering on February 21-22, 2007. AIU claims the only data that exists on a daily basis from which any volumetric error can be calculated is the daily SPL withdrawal numbers. The correction volume, AIU states, was calculated based on information available to make the correction. AIU adds that the referenced transmitters are calibrated each fall prior to the withdrawal season and adjusted as needed so any variances in measured values are minor.

Mr. Lounsberry's third concern, that the 2.75% error rate for a fully-open valve is unexpectedly high, is, in AIU's view, also unwarranted. AIU claims the error-rate calculation was based on an analysis of actual data by AmerenIP. AmerenIP says it determined the 2.75% error by comparing actual daily flows from both the SPL and North Pipeline ("NPL") orifice runs, adjusted for the correction to the NPL flows for orifice installation problem and then correcting the SPL flow so that the daily sum of the adjusted NPL and corrected SPL flows matched the ultrasonic meter daily volume. AIU insists that the correction method made use of the best information available. AIU says the historical daily 2000 to 2007 volumetric data was available for the NPL and the SPL, but not by primary or primary and secondary run volumes. According to AIU, it would therefore be impractical to try to apply separate primary and secondary run corrections. AIU claims that based on the hourly test at 1600 Mcf/hour, with both primary and secondary open, the accumulated volume error percentage was 2.246%, and not negligible. AIU states that the flow exceeding 35,000 Mcf/day SPL correction of 2.75%, derived from correcting the daily NPL and SPL volumes to ultrasonic meter volumes, is comparable to the test measured error over one hour of 2.246%.

AIU says it attempted to identify all causes for the differences between the SPL orifice volumes and the ultrasonic meter volume. AIU insists the testing performed was thorough and resulted in the leaking valve being identified as the most significant problem that resulted in the differences in measured volumes. AIU also states that real

time testing requires the field to cease normal withdrawal operations and requires operators to modify flow rates, open and close valves, and verify readings at several points along the data communications path. When testing the SPL meters, AIU says withdrawals to the NPL are stopped, and the flow rates are adjusted for testing which impacts the gas dispatch function. AmerenIP concluded that it had identified the cause of the measurement error and it would be unreasonable to further disrupt the dispatch function and tie up operators for long periods of time to determine the source of errors beyond what was performed. In AIU's view, Mr. Lounsberry's theoretical concerns ignore AmerenIP's reasoned and reasonable approach to the leak investigation and calculations.

According to AIU, Mr. Lounsberry's fourth concern, that the leak measurements were extrapolated from data gathered during a one-month review, overlooks the fact that the review period could not have begun sooner, nor been fair and representative of the leak after February 20th. AIU indicates the ultrasonic meters at Hillsboro were placed into service on January 23, 2007, so a comparative analysis could not have been started sooner than that date. On February 20th, AIU says the NPL plates were installed correctly and the SPL secondary run problem was discovered and isolated. AIU claims any information collected after corrective action was completed would not be useful for determining prior period corrections. In AIU's view, the review period selected represents the best available information regarding the measurement error. AIU believes that since the information from the review period was the best information available, it was appropriate to use that information as a basis for estimating the measurement error for 2000-2007.

AIU argues that Mr. Lounsberry's position, that conditions during the 1-month review period may not have mirrored conditions during the rest of the 7-year adjustment period, does not support a conclusion that the estimate of the leak was unreasonable. According to AIU, there were no physical changes made to the piping on the SPL meter runs from 1999 to 2007. AIU says the orifice plates in both runs have not been changed, nor has the computation method for volumes changed so the measurement system for the SPL orifice meter runs over the prior 7 years is identical to the system used during the month for the correction. AIU claims the test included flow rates over the entire flow range simulating flowing conditions. The actual flows, AIU asserts, were matched daily back to the tested flows to come up with the error amounts. AIU contends there is no reason to believe that circumstances did not remain reasonably similar throughout the 7 year time period. Given that there were no significant changes, AIU believes its extrapolation was appropriate.

Mr. Lounsberry's fifth concern, that meters connected in series will typically exhibit some variance, is de minimis, according to AIU. AIU acknowledges that there will be variances between meters. AIU believes, however, that the impact of any such variances on the measurement error calculation will be minimal. AIU says the measurement error calculation is an estimate. AIU states that the ultrasonic meter measurement uncertainty is much less than volumes determined by the orifice meter system. AIU say it has high confidence in the computed volumes from the ultrasonic

meters and believes that the variances, and their impact on measurement error calculation, would not be significant.

In AIU's view, Mr. Lounsberry's reason for rejecting the current base gas adjustment, that AmerenIP should have identified the valve failure more swiftly, is an unfair criticism of AmerenIP's approach to identifying and correcting system issues. Mr. Lounsberry's criticisms of the operation of Hillsboro relate to events that took place prior to 2004. AIU insists that since 2004, AmerenIP has undertaken a number of steps to address these events. AmerenIP says it only discovered the leaking valve after the ultrasonic meter was installed, and AmerenIP compared its measurements with the existing master metering total withdrawal volumes. AmerenIP claims the leak was too small to be detected on the orifice recording chart or register on the station control system and noise through the leaking valve was not observed because of noise generated by the flow control valve down stream of the leaking valve masked any noise from the run change valve. AmerenIP also asserts that the annual maintenance performed on the valve indicated that the pneumatic operator rotated full open and back to full closed position each fall prior to withdrawal season. AmerenIP maintains that it had no reason to suspect that gas was by-passing the closed run changer valve until it compared the volume through the ultrasonic meter placed into service in January 2007.

Mr. Lounsberry asserts, however, that the past problems at Hillsboro are still relevant to this proceeding because he believes they relate to the issue of the discovery of the leaking valve problem in 2000. Mr. Lounsberry believes that AmerenIP should have discovered the leak before 2007, given the focus on issues at Hillsboro in 2004, and that AmerenIP's failure to review or discover that problem at that time is a reflection on how AmerenIP operated its storage fields during the time period. AIU believes this concern is mistaken. AIU states that AmerenIP made annual checks on the valve in question, but the purpose of these checks was to verify that the valve opened and closed at the appropriate differential pressure signals across the primary orifice run. Given the nature of the leak, AIU insists that it is unlikely the leak could have been discovered sooner, even during the investigations of issues at Hillsboro in 2004. AIU says AmerenIP personnel made no observations that gas was leaking from the valve when it was in the closed position until after the ultrasonic meter was installed and a difference was observed in the calculated volumes. In AIU's view, the failure to find the leak was not related to problems at Hillsboro, and the fact that there were past investigations does not mean the leak would have been found any sooner. AIU also maintains that AmerenIP would have had to discover the leak before April of 2004 to have made any difference in the adjustment sought in this proceeding. AIU says the estimated errors using AmerenIP's method did not affect the base gas values after April of 2004.

According to AIU, Mr. Lounsberry's suggestion that AmerenIP could have identified the valve leak through a "block and bleed" test is unfounded. AIU says the valve manufacturer's manual makes no mention of performing the procedure in order to verify the valve seats are seating properly; the manual does not mentioned this is a procedure that should be performed as ongoing maintenance of the valve; and the

procedure is not a common practice to perform. AIU contends the suggestion that AmerenIP should have performed this procedure reflects the benefit of hindsight, but AmerenIP had no reason to discover the leak prior to the installation of the ultrasonic meter. AIU adds that the consultant (Peterson) who performed the comprehensive 1999 metering study at Hillsboro did not suggest conducting such a test, which further demonstrates that this is not a common practice.

b. Staff's Position

Mr. Lounsberry opposes AIU's attempt to increase the base gas inventory value at the Hillsboro field by $2,841,000. He has four reasons for disputing AIU's request. First, Mr. Lounsberry does not consider AIU's logic in determining the timing of the metering error at Hillsboro during the years 2001 to 2004 valid. Second, he determines that AIU had inadequate support for the assigned value. Third, Mr. Lounsberry questions the validity of certain assumptions that AIU made as part of the calculation. Finally, he notes that given the history and magnitude of the problems that AmerenIP has experienced at the Hillsboro field, AmerenIP should have, as part of its overall investigation of the various problems it has experienced at Hillsboro, conducted a review of the integrity of the valve at a much sooner date and, as such, AmerenIP should have never found itself in this position.

AIU notes that as a result of new metering installed at Hillsboro storage field in 2007, AmerenIP discovered a discrepancy between the new metering and the original metering used to measure the volume of gas withdrawn from the Hillsboro field. AmerenIP conducted a series of tests that demonstrated there was a leak in the valve that separated the primary and secondary metering runs in the original metering set that measured gas flowing to the south of the Hillsboro field. AmerenIP claimed that this leaking valve allowed gas to pass undetected and unmeasured through the secondary metering run. AmerenIP selected the time period of 2000 to 2007 to reflect the measurement error.

Staff says AmerenIP's assumed timing for this metering error impacts the recoverable base gas valuation in 2001 to 2004 because it assumed this metering error occurred in addition to the metering error that was at issue in last rate case, Docket No. 04-0476. AmerenIP contends that both errors understated the withdrawals from the Hillsboro field, meaning that it had withdrawn gas from the Hillsboro field in excess of those levels that it maintained in its top gas volumes and had unknowingly withdrawn gas from its recoverable base gas inventory.

Mr. Lounsberry takes issue with AmerenIP's logic in selecting the starting date for the valve leak. In particular, he notes that AmerenIP assumed the leak existed for the period 2000-2007. Staff says AmerenIP's selection of that time period was based upon the fact that the valve was rebuilt in 1993 and the leak was discovered in 2007. Since the exact date of the leakage could not be determined by AmerenIP, Staff says it decided to go back to half the amount of time since the valve was installed. Staff believes that AmerenIP's decision regarding the timing of the valve leak was pure

speculation and is not sufficient basis to support the just and reasonable threshold for AmerenIP's request to increase the recoverable base gas costs at Hillsboro.

Mr. Lounsberry also expresses a concern regarding the lack of support that AmerenIP had for the volumes it calculated. Specifically, he notes two distinct concerns. First, AmerenIP's inconsistent operation of the Hillsboro storage field creates a situation where it is not possible to reasonably use reservoir information to support any adjustments. Second, AIU's current proposal is at odds with the information it provided in the prior rate case regarding the shortfall that existed at the Hillsboro field as of November 30, 2003, as detailed in the 2004 Hillsboro Report.

Staff asserts that AmerenIP's inconsistent operation of the Hillsboro field creates a situation where it is not possible to reasonably use reservoir information to support any adjustments. This viewpoint, Staff claims, was also shared by AmerenIP personnel in a November 20, 2006, report noting that in September 2004 AmerenIP had just completed a 2.2 Bcf addition to Hillsboro's inventory that completed AmerenIP's 3-year replacement (2003-2005) of the 5.8 Bcf inventory shortfall that IP found at the Hillsboro field in 2003. According to Staff, this report indicated that, as a result of replacing the 5.8 Bcf of inventory over the prior 3 years, the hysteresis curve is not stable enough to aid in determining a gas loss correction. Staff says AmerenIP personnel estimated that after 3 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.

Mr. Lounsberry states that his understanding of this report was to represent that AmerenIP had no reliable support for adding any gas to the Hillsboro field because the field's reservoir information changed too frequently to be used to determine any values. Staff claims this also means that AIU's request is speculative and that it can not support the just and reasonableness of its proposal. In response to Mr. Lounsberry's concerns, AIU notes that AmerenIP used pressure and volume data to support the measurement error calculation and that it considered this data as sufficient to support the adjustment. AIU also notes that while Staff had previously questioned the methodology and conclusions on reservoir engineering studies in many previous AmerenIP cases, Staff never questioned the validity of the wellhead pressure measurement that it claims supports its request.

Aside from its previous discussion regarding the lack of reliable reservoir data, Mr. Lounsberry provided two additional reasons to dispute AIU's statements. First, while AIU's statement that Staff never disputed AIU's use or calculation of wellhead pressure measurement in prior cases is accurate, Staff did question AmerenIP's methodology and conclusions on reservoir engineering studies in those cases. Staff says the fact that AmerenIP, in the prior cases, did not rely solely upon the wellhead pressure measurement information to support its position suggests the other methodologies that AmerenIP employed in those proceedings were deemed by it to be superior to the calculations that AmerenIP provided in the instant proceeding that consider only one measure, wellhead pressure.

Second, Mr. Lounsberry understands that there are many methods available to AmerenIP to determine if a particular storage field has an inventory shortfall. Staff says a comprehensive review should be done to support an inventory shortfall; reliance should not just be placed on one measure whose information may or may not be consistent with other measures available to the utility. Aside from Mr. Lounsberry's concern regarding AmerenIP's calculations, AmerenIP also notes that it intends to conduct a detailed reservoir engineering study after the end of the 2008 injection season. AmerenIP indicates that this study was not performed in 2005 because it was of the opinion that there was insufficient information available to form a reliable conclusion as to whether any further adjustment to the original 5.8 Bcf correction was appropriate.

Mr. Lounsberry does not dispute AmerenIP's need to conduct the study, but believes that AmerenIP's statement that there is insufficient information available to form a reliable conclusion as to whether any further adjustment to the original 5.8 Bcf correction was appropriate is contrary to its claim that AmerenIP has valid support for the addition of about 1.1 Bcf of gas that would increase the base gas valuation of Hillsboro by $2,841,000. Staff argues that the information is either available or it is not; AIU can not have it both ways. Mr. Lounsberry believes that AmerenIP does not currently have any reliable information to support the 1.1 Bcf addition.

Mr. Lounsberry expresses concern that AmerenIP had to make a number of assumptions when it calculated the measurement error volumes associated with the leaking valve at the Hillsboro field. He also asserts that AmerenIP's situation does not lend itself to provide a good basis to extrapolate out the measurement errors it found over a 7-year period. In particular, Mr. Lounsberry identified 5 areas of concern: valve leakage could have worsened over time; other errors could have existed; a 2.75% error existed even when valve was fully open; using one month to extrapolate out 7 years; and all meters in series show some difference in readings.

Mr. Lounsberry expresses concern that AmerenIP assumed the correction values it calculated could be applied for the whole period that AmerenIP estimates the measurement error took place. Staff asserts that it is possible that the valve leak worsened over time, meaning that AmerenIP's calculation overstates the initial volumes that were not measured. AIU's response to this concern is that it had no indication that the leak worsened over time. AIU also notes that it would be difficult to identify when such worsening of the leak would occur or at what rate the worsening would occur. Staff agrees that given the lack of data to support when the valve leak started or for how long the leak existed, it would be virtually impossible for AmerenIP to determine if or when such worsening of the valve leak would occur or at what rate the worsening would occur. Staff claims AIU has not stopped to consider the reasonableness of its assumption regarding the valve leak. Staff asserts that AmerenIP simply found a value leak and then blindly assigned it to the time period that AmerenIP assumed the error occurred.

According to Staff, AmerenIP assumed that all of the errors it found were either caused by the leaking valve or the incorrectly installed orifice plate. Staff suggests that on an orifice meter, there are multiple items that can cause error, such as a pressure or temperature probe that is out of calibration. Staff contends it is not clear if AmerenIP eliminated all of the potential causes of measurement error when it performed its review. Staff says that if AmerenIP did not eliminate all potential causes for the error, then it could have under or overstated its measurement error estimate. AIU responds that, while it can not determine that "all" of the errors observed were either caused by the leaking valve or due to the orifice plates, AmerenIP believes the leaking valves or the orifice plate were the dominate sources for the observed errors. AmerenIP also indicated that the pressure and temperature used for the orifice measurement relative to the measurements used for the ultrasonic meters would decrease the volumetric differences between the orifice measurement and the ultrasonic measured values.

Staff says that AIU's reference to the decrease in volumetric differences between orifice measurement and ultrasonic measurement due to the pressure and temperature variances between the two metering sets confirms Staff's point. Staff does not know the exact time period AmerenIP reviewed to make its statement, but the basic concept is that, depending on the frequency that AmerenIP calibrated its temperature and pressure probes and how much variance those probes could develop, the measurement calculation will differ over time, creating a situation where the volume differences either decreased or increased. Staff argues that given AmerenIP's decision to extrapolate out the measurement impact it calculated over a 7-year period, any variance in measurement can be significant and it does not appear that AmerenIP attempted to account or identify the reasons for those errors.

Staff also expresses concern over the fact that AmerenIP calculated an error of 2.75% even when the valve was fully open. Staff says that since AmerenIP claimed the reason for the measurement error was due to the leaking valve, it would not expect a fully open valve with a leaking seal to create a measurement error of that magnitude. Staff's understanding of AmerenIP's explanation for the measurement error is that some quantity of gas passed through the valve that the secondary metering run could not measure because the amount was too small for the meter to pick up. Staff claims that once the valve is fully open, the secondary metering run is measuring a considerable amount of gas that should account for all gas volumes whether the valve is leaking or not. Staff contends that the measurement error under that circumstance should be negligible, not a significant amount like 2.75%.

AIU responds by indicating that the analysis of the 2.75% error was determined from actual daily flows from both of the orifice runs. AmerenIP also indicates that based on an hourly test flow rate of 1600 Mcf/hour, with both primary and secondary metering runs open, the accumulated error percentage was 2.246% and not negligible. Therefore, AmerenIP believe the assumption that for flows exceeding 35,000 Mcf/day there is a 2.75% error is comparable to the error shown for just one point in time.

Staff does not dispute AmerenIP's calculation of the error percentage, the fact that an error exists lends support to its second concern that AmerenIP had not identified all of the causes of the measurement error. According to Staff, a 2.75% variance between two sets of meters is considerable and AmerenIP should have attempted to determine the cause of this error beyond the general conclusion that the error is a result of the valve leak. AIU responds by noting that when it was calculating its measurement errors, it was disrupting the manner in which the Hillsboro field normally operated. AIU states that AmerenIP had identified the cause of the measurement error and it would be unreasonable to disrupt the dispatch function further and tie up operators for long periods of time to determine the source of errors beyond what was performed. Staff also does not dispute that AmerenIP was likely disrupting the manner that the Hillsboro storage field operated when it was conducting various measurement tests. Staff maintains, however, that AmerenIP found an almost 3% error in a situation where the error reading should have been negligible and AmerenIP did not bother to investigate the cause of the problem further.

Staff also argues that it is not possible that all of the circumstances occurring for that one month were exactly the same for all of the months over the prior 7 years. In other words, Staff claims AmerenIP had a snapshot of what occurred, but has no way to determine if the circumstances that occurred during that month were identical to the circumstances for the prior 7 years. AIU responds that the selected review period represented the best available information regarding the measurement error. Since it was the best information available, AIU claims that it was appropriate to use that information as a basis for estimating the measurement error for 2000-2007.

Staff states that, in theory, two meters placed in series would show no variance; however, the reality is that all meters have some variance between each other. Staff indicates this could occur because no meter is perfect and meter manufacturers do not guarantee absolute accuracy with their meters. Staff says there is usually an accuracy range provided, such as plus or minus 1%. Therefore, Staff indicates that two meters in series will likely not correlate directly to each other. As a result, Staff expressed a concern that a small portion of AmerenIP's correction it is attempting to fix could, in reality, not be a measurement error.

In its Reply Brief, Staff notes that AmerenIP argues that it is not required to use any particular type of study to demonstrate prudence, and that no one has challenged the two forms of input data that AmerenIP is using to support measurement error correction, namely pressure and inventory. According to Staff, AmerenIP indicates that, contrary to Staff's concern that AmerenIP could have used superior methodologies, it used valid reservoir engineering techniques to determine gas loss. Staff disagrees. Staff contends it has not directed AmerenIP to make use of any specific type of analysis to support the adjustments. Staff claims it pointed out that AmerenIP had used in its prior rate case a reservoir simulator model that its witness from that proceeding indicated was superior to any static method of predicting reservoir behavior. Staff expresses concern that, given the time and money spent on developing this model, Staff would have expected AmerenIP to make use of the model had it been available.

Staff says that contrary to AIU's claims, this is not a directive from Staff to make use of a specific analysis. Instead, Staff indicates that AmerenIP's analysis failed to support its request. Staff does not agree that the reservoir engineering techniques AmerenIP used were valid under its current circumstances.

c. Commission Conclusion

AIU proposes the addition of $2,841,000 to the Hillsboro base gas account, an increase in rate base. AIU claims the addition is necessary to account for base gas lost through a valve leak and is necessary to maintain the deliverability of the Hillsboro Storage Field. AIU argues that AmerenIP used the best techniques available to estimate the lost gas and that it should be allowed to include the base gas in rate base.

Staff objects to AIU's proposal to include the additional base gas in rate base. Staff does not consider AIU's logic in determining the timing of the metering error at Hillsboro during the years 2001 to 2004 valid. Staff contends that AIU has not adequately supported the amount it seeks to include in rate base. Staff questions the validity of certain assumptions that AIU made as part of the calculation. Given the history and magnitude of the problems that AmerenIP has experienced at the Hillsboro storage field, Staff asserts that as part of its overall investigation of the problems at Hillsboro, AmerenIP should have conducted a review of the integrity of the valve at an earlier date.

The Commission observes that this issue is strikingly similar to the issue decided immediately above. In both instances, AIU asserts that there has been lost base gas, has estimated the volume of missing gas, and requests authorization to include the additional base gas in rate base. Also in both instances, Mr. Lounsberry objects to AIU's request. Mr. Lounsberry again insists, among other things, that AIU failed to adequately demonstrate that AmerenIP's estimate of the lost base gas is reasonable or appropriate. Just as it did in Docket No. 04-0476, the Commission finds Mr. Lounsberry's expert testimony to be convincing. The Commission concludes that AmerenIP failed to adequately demonstrate that its estimate of the lost base gas is reasonable. As a result, the Commission adopts Staff's recommendation and AIU's request to include the additional base gas in rate base is denied. In the Commission's view, this decision regarding lost gas at Hillsboro is consistent with, and is required by, the appellate court decision discussed earlier in this Order.

D. Approved Rate Bases

Based on the determinations made above, the rate bases for AIU's respective service territories are approved as shown below and in the Appendices attached hereto.

	AmerenCILCO	AmerenCIPS	AmerenIP
Electric	$240,625,000	$443,743,000	$1,254,459,000
Gas	$183,734,000	$181,735,000	$518,857,000

V. OPERATING REVENUES AND EXPENSES

A. Introduction

Schedules showing the operating revenues, expenses, and income at present and recommended rates for the test year ending December 31, 2006, were presented by AIU and Staff.

B. Resolved Issues

1. Annualized Labor and Pro Forma Wage Increases

Staff witness Ebrey recommends adjusting annualized labor expense to reflect a 3% wage increase effective July 1, 2007, based on her assessment of actual wage increases approved in December 2007. AIU agrees with this adjustment.

Ms. Ebrey also recommends disallowing wage increases for management employees projected for April 1, 2008. AIU responds that the wages already increased to slightly beyond the estimated levels as of the time of the filing of rebuttal testimony, thus the increases are known and measurable. In its rebuttal testimony, Staff accepts the AIU proposed rebuttal labor adjustment for management employees in all six rate cases. The Commission finds Staff's proposed adjustment to increase labor expense to reflect the July 1, 2007, wage increase reasonable and is hereby adopted. The Commission also finds AIU's proposal to reflect the April 1, 2008, management wage increase reasonable and is hereby adopted.

2. Injuries and Damages Expense

Rather accepting AIU's proposal for calculating injuries and damages expenses, Staff proposes using a five year average in calculating the expenses for AmerenCILCO's, AmerenCIPS', and AmerenIP's gas operations. For these five utility operations, AIU does not object to Staff's proposed methodology. The Commission finds this approach to be reasonable and it is hereby approved for the five utility operations identified. The issue of how injuries and damages expenses should be calculated for AmerenIP's electric operations is address later in this Order.

3. Employee Benefits Expense

Staff proposes an adjustment to AIU's Employee Benefits Expense. For purposes of this proceeding, AIU accepts Staff's proposed adjustment to Employee Benefits Expense. The Commission finds Staff's proposed adjustment to the employee benefits expense reasonable and it is hereby approved.

4. Reliability Audit

With regard to the Liberty reliability audit performed for AIU, Staff witness Ebrey proposes to only allow the maximum estimated price of Liberty, $2,897,880, and the actual rental of office space for 12 months per the lease agreement of $29,290, allocated to each electric utility consistent with AIU's proposal. AIU accepts Staff's proposed adjustment. The Commission finds Staff's proposed adjustment to the reliability audit expense reasonable and it is hereby approved.

5. Storm Costs

Staff witness Everson recommended use of a separate subaccount to track costs associated with storm restoration. After reviewing AIU's responsive testimony, Ms. Everson withdrew her recommendation. The Commission finds that there is no longer a contested issue related to storm costs and the Commission takes no action.

6. Interest on Customer Deposits

Staff witness Everson proposes using a 3.5% rate as the interest rate on customer deposits, which was accepted by AIU. AIU believes the adjustment should be reflected as an adjustment to Customer Accounts Expense, to which Staff does not object. The Commission finds the proposed treatment of customer deposits to which AIU and Staff agree to be reasonable and it is hereby approved.

7. Accounts 856, 863, 874, and 887

In direct testimony, Staff witness Lounsberry raises concerns regarding Accounts 856, 863, 874, and 887. In its rebuttal, AIU explains the nature or circumstances surrounding the costs (in particular, that costs shift between the AIU transportation and distribution Operations and Maintenance ("O&M") accounts from year to year). Mr. Lounsberry found AIU's explanation acceptable and withdrew his proposed adjustment.

8. Advertising Expense

Staff proposes an adjustment to AIU's proposed level of Advertising Expenses, which AIU accepts. The Commission finds Staff's proposed adjustment to advertising expenses to be reasonable and it is hereby approved.

9. Industry Association Dues Expense

Staff proposes and adjustment AIU's electric utilities' industry association dues, which AIU accepts. The Commission finds Staff's proposed adjustment to AIU's electric industry association dues expense reasonable and it is hereby approved.

10. Vegetation Management/Tree Trimming

In response to AG/CUB witness Effron's direct testimony, AmerenIP agrees that its tree trimming expenses should be reduced by $1,932,000. Although Mr. Effron originally proposed an adjustment to AmerenCIPS' pro forma tree trimming expenses, after reviewing Mr. Stafford's rebuttal testimony explaining why no such adjustment was necessary, Mr. Effron withdrew his proposed adjustment. The Commission finds that the agreed adjustment to AmerenIP's tree trimming expense is reasonable it is hereby approved.

11. Midwest Independent System Operator Expenses

AmerenIP agrees to the proposal to eliminate from its delivery service revenue requirement $1,037,000 of payments to the Midwest Independent System Operator, which AmerenIP charged to Account 928 "Regulatory Commission Expenses" in 2006. The Commission finds the proposal to adjust Account 928 for AmerenIP to be reasonable and it is hereby approved.

12. Retired Production Worker Pension and Medical

In his direct testimony, Staff witness Lazare expresses concern about whether pension and health care costs for AIU retirees who worked at production facilities that have since been divested from AIU should be included in test year A&G expenses. AIU accepts Staff's proposed adjustments. The Commission finds Staff's proposed adjustment related to the retired production worker pension and medical expense to be reasonable and it is hereby approved.

13. Test Year NESC Violation Correction Costs

In response to Staff's concerns regarding the costs to correct National Electrical Safety Code ("NESC") issues during the test year, AIU agrees to track the costs of repair or replacement of identified down guy, overhead guy, and double-cross arms at affected railroad or interstate highways. AIU agrees to replace those railroad or interstate highway crossings that have only a single cross-arm, but under new NESC standards should now have a double-cross arm. Additionally, AIU agrees to bear all 2006 test year costs associated with the remediation of NESC violations. The Commission finds it appropriate for AIU to track the costs of repair or replacement of facilities that were originally constructed in violation of NESC to be reasonable. Additionally, the Commission agrees that AIU should not recover from ratepayers the costs incurred during the test year for these types of activities.

C. Contested Issues

1. AMS Charges

a. AIU's Position

AIU argues that accepting Staff's proposed adjustment of $48.3 million representing AMS charges would pose a significant threat to AIU's financial health and that it is entitled to recover the charges AMS assesses on AIU for essential utility services. AIU alleges that Staff's adjustment arises from its invention of a new allocator that Staff applies to the total AMS charges assessed on all Ameren subsidiaries. AIU submits that Staff's allocator is based on an assumption that has never been tested, proven, or used in any jurisdiction and the allocator presupposes that all subsidiaries will consume services from a common service company in direct proportion to their size, as measured by the simple arithmetic average of three metrics: total assets, total employees and non-fuel O&M. AIU avers that should the Commission accept this adjustment, AIU will under-recover its costs by $48 million. Were this to happen, AIU claims it would be forced to make cuts in service in order to maintain its financial condition.

AIU points out that in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), the Commission directed AIU to provide, in its next delivery service case, a study regarding the services and related costs that AMS provides to AIU. AIU submits that in compliance with the Commission's directive, it hired a consulting firm, Concentric, to prepare a study of the services and related costs that AMS provides to AIU. AIU says the Concentric study benchmarks the costs of specific services provided by AMS to AIU. AIU notes that the services studied include finance, information technology, human resources, procurement, legal, government affairs, and corporate communications, which account for approximately 60% of total AMS expenses charged to AIU. AIU states that for each of the services provided by AMS, the total cost of providing the service was compared to both other utilities and to non-utility companies. According to AIU, AMS costs for services compared favorably to the peer companies.

AIU explains that during the review of AMS costs allocated to AIU, Concentric employed a cost causation standard to assess the reasonableness of the allocated costs, and under cost causation principles, the standard of reasonableness was whether the costs allocated to each of the individual utilities was representative of the benefits realized by each company. AIU further explains that AMS costs are recorded in various SRs. Each SR relates to a specific scope of work by an organizational unit within AMS. AIU notes that when created, the SR must consist of a project name, a description of the work to be performed, and the allocation factor to be used to distribute the costs assigned to each SR. The appropriate allocation factor is determined from the list of available allocators set forth in the General Services Agreement ("GSA"). The SR is signed off on by representatives of each Ameren subsidiary which will benefit from the work performed and a representative of AMS.

AIU argues that it has complied with the Commission's directive in the last proceeding, that it has submitted substantial evidence demonstrating that its A&G costs in general, and AMS charges in particular, are reasonable, consistent with those incurred by comparable entities in the market, and should be approved as proposed.

b. Staff's Position

Staff argues AIU proposes a disproportionate allocation of AMS costs to AIU without providing a reasonable explanation or adequate support. According to Staff, there are systematic problems with the allocation of AMS costs that not only support Staff's proposed $48.3 million reduction in these costs, but further call into question the full amount that AIU proposes to recover from ratepayers. Staff submits that its proposed adjustment of $48.3 million would make the allocation of AMS charges to AIU consistent with the relative size of each company.

Staff points out that AMS costs are a significant portion of test year costs. Staff notes that AIU seeks to recover a total of $213.7 million in AMS costs from ratepayers for the test year. Staff further notes that the Commission has expressed its ongoing concern about the recovery of these costs from ratepayers, and Staff submits that AIU has yet to satisfactorily address these concerns. Staff further opines that a review of the evidence in this case shows that there are fundamental problems with the way AMS costs are allocated to AIU.

Staff argues that the first step in developing its adjustment is to determine what would be an appropriate allocation of AMS costs to AIU based on the relative size of each company. According to Staff, there are three measures to determine the relative size of a company: assets, non-fuel O&M, and number of employees. Staff notes that assets are the investments on which a company seeks to earn a return. Staff contends the level of assets is an important determinant of their level of business success. Staff notes that non-fuel O&M reflects expenses incurred to operate a company, and Staff submits that the levels of these costs provide an indicator of the relative costs of operating a company. As to number of employees, Staff suggests a larger company will entail more activity and require more employees to ensure that tasks are performed.

Staff witness Lazare found that AIU accounts for 34.0% of assets; 33.9% of employees; and 36.8% of non-fuel O&M expenses for Ameren as a whole. Staff submits that with no specific evidence to indicate that any of these measures is more relevant than any other, the simple average of these percentages is used to find that AIU constitutes 34.9% of Ameren on a size basis. Since AMS charged a total of $473.6 million to all Ameren subsidiaries in 2006, Staff suggests that the share that AIU should receive based on its size is 34.9% of that total or $165.4 million. Staff further argues that since AIU proposes to allocate $213.7 million of AMS costs to AIU for the test year, an adjustment of $48.3 million to AMS costs allocated to AIU is appropriate.

Staff points out that AIU has a responsibility in this case to demonstrate that it received a reasonable share of AMS costs, particularly in light of the Commission's

concern in Docket Nos. 06-0070/06-00071/06-0072 (Cons.) about the allocation relative to other Ameren subsidiaries. However, Staff suggests that AIU failed to explain why it receives a disproportionate share of these costs relative to its size. Therefore, Mr. Lazare proposes an adjustment to remove the "excess" share of AMS costs.

Staff argues Mr. Lazare's proposed adjustment represents a conservative reduction in AIU's proposed revenue requirement. Staff states further that the evidence reveals fundamental problems with the SRs, which are the building blocks for the allocation of AMS costs among Ameren subsidiaries. The process by which these SRs are allocated to AIU, Staff argues, is riddled with errors, and the resulting allocations of AMS costs as a whole are called into question.

Staff complains that based upon its review, AIU witness Adams identified only three SRs that were inaccurately recorded, resulting in an under allocation of $23,869 to AIU by AMS. Staff is not comfortable with Mr. Adams' conclusion that the services described and allocations for each SR are reasonable. Staff suggests that the focus of this case should be on AIU's failure to support its disproportionate allocation of AMS costs. Staff posits that should AIU succeed in changing the subject to focus on a small number of SRs, AIU and other utilities will be encouraged to provide even less support for their ratemaking proposals in the future.

In addition, Staff disagrees with AIU that its bench mark study justifies AMS costs allocated to AIU. Staff argues the study failed to answer a basic issue raised by the Commission in its Order on Rehearing in Docket Nos. 06-0070/06-0071/06-0072 (Cons.). The Commission in that proceeding stated that there was insufficient evidence to indicate that AIU received a reasonable allocation of AMS costs relative to other Ameren affiliates. This statement emphasizes, according to Staff, the need to examine AMS costs for all Ameren companies, not just those directly regulated by the Commission. Staff suggests that the Commission appropriately recognized that the fairness of the allocation of common AMS costs to one group of Ameren companies can only be assessed when comparable information is provided on the allocation received by others. Staff notes that AMS costs are shared by all Ameren subsidiaries, and that it is essential for Ameren to show that the allocations to AIU are reasonable compared with other Ameren subsidiaries.

According to Staff, the Commission must assess the reasonableness of all costs passed along to AIU ratepayers, including AMS costs. Staff suggests however, that the study performed by Mr. Adams fails to satisfy this requirement. Staff notes that while Mr. Adams identifies five findings he made from the study in his rebuttal testimony, none of these findings directly discuss how AMS costs are allocated to other Ameren subsidiaries. Staff suggests further that the study only examined the A&G component of AMS costs, while AIU is additionally requesting recovery of AMS charges that are outside the A&G area.

c. Commission Conclusion

As the parties are aware, the Commission takes seriously its obligation to assure that affiliate costs are not improperly passed along to utility ratepayers. AIU and AMS operate under the GSA previously approved by the Commission. The GSA calls for direct assignment of AMS costs where possible. In addition, the GSA contains numerous allocation factors that are to be used when costs can not be directly assigned. While AIU is not necessarily entitled to recover from ratepayers all AMS costs allocated pursuant to the GSA, the GSA is intended to assist the Commission in ensuring that AIU and ratepayers are not assessed improper costs by affiliates.

Rather than rely upon direct assignment and the numerous allocation factors contained in the GSA, Staff assumes that all AMS costs should be allocated among affiliated entities on the basis of their relative size. That assumption is inconsistent with the GSA approved by the Commission and, in the Commission's view, is not a reasonable assumption. Under Staff's proposal, for example, assuming that AMS provides services to AIU to prepare and litigate a rate case, 65% of such costs would be allocated to unregulated affiliates. Unfortunately, it is easy for the Commission to envision numerous situations where AMS costs would not properly be allocated among Ameren companies based upon the relative size of the companies. The Commission can envision situations where costs would be improperly allocated to AIU as well as situations where costs would be improperly allocated to unregulated affiliates. The Commission concludes that Staff's single allocator is too simplistic and does not produce reasonable or appropriate results.

While not perfect, the Commission finds the Concentric study of AMS charges to be helpful. The Commission believes that the testimony of Mr. Adams and the Concentric study demonstrate that test year level of AMS costs assessed to AIU are reasonable. In summary, the Commission concludes that Staff's proposal should be rejected and that the record supports a finding that the AMS costs assigned to AIU are reasonable and should be included in operating expenses.

In its Brief on Exceptions, Staff complains that the conclusion in the Proposed Order did not specifically address each and every alleged flaw it identified in AIU's AMS cost analysis. To be clear, the Commission considered each aspect of Staff's arguments, and the Commission does not believe that AIU's evidence is perfect. The Commission concludes, however, that despite any flaws in the evidence presented by AIU, it is superior to Staff's proposal for establishing the amount of AMS costs that should be reflected in rates. Section 10-103 of the Act mandates that the Commission make its decision based exclusively upon the record. The Commission finds Staff's proposal unworkable and unreasonable, thus, the record supports a conclusion that the test year level of AMS costs assessed to AIU is reasonable.

In its Brief on Exceptions, Staff also claims that the conclusion in the proposed order is inconsistent with the decision in Docket Nos. 06-0070/06-0071/06-0072 (Cons.). The Commission notes, however, that in the previous AIU rate cases, the

basis of Staff's proposed disallowance of AMS costs was not an allocator based upon the relative sizes of AIU and other affiliates. In that case, the Commission identified specific costs that were not adequately substantiated. Here, the record does not support a finding that Staff's proposed allocation factor is reasonable. Of the alternatives available in the record, the Commission finds that the record supports a conclusion that Staff's proposed disallowance must be rejected. This does not mean that in future cases Staff can not propose disallowance of AMS costs if it can develop an appropriate basis.

2. Incentive Compensation Costs

a. AIU's Position

AIU proposes to recover a total of $5,238,000 in incentive compensation expenses in rates. AIU witness Bauer asserts that incentive compensation is a common and necessary component of the total compensation package for employees in the electric and gas utility industry. Over the next decade, according to AIU, the electric and gas utility industry is expecting a substantial number of employee retirements, thus resulting in increased competition for talent. AIU argues that in order to attract and retain qualified employees, and to motivate employees to perform to the best of their ability, AIU must ensure that its total compensation package is competitive. According to AIU, a competent, stable, focused and motivated workforce is critical to providing excellent service to its customers. AIU believes that by using both base and incentive pay, it is able to limit its fixed costs (base pay), yet still reward employee performance (incentive pay).

According to AIU, its incentive compensation plan costs are designed in a manner consistent with market practice. Additionally, AIU argues its incentive plans require achievement of operational performance, thus the plans are designed in a prudent and reasonable manner. AIU claims no party has contested the prudency or reasonableness of the AIU's overall level of total employee compensation. Therefore, AIU believes its proposal to pass the costs along to ratepayers should be accepted. AIU argues that the incentive compensation plan benefits the utility's customers and the costs should be recoverable in rates.

According to AIU, it provided evidence of operational and individual goals that can be considered and paid independently of financial goals under the plans. For the 2006 test year, AIU argues key performance indicators were associated with incentive payouts under the plans, such as O&M budget compliance (weighted 20%), capital budget compliance (weighted 20%), safety (weighted 25%), gas O&M (weighted 10%), customer service (weighted 10%); and reliability (weighted 15%). AIU claims each of these metrics benefits AIU`s customers by enhancing service, increasing service reliability, and/or increasing the efficiency of operations.

AIU asserts that it presented evidence providing "financial-based" and "performance-based" percentage breakdown amounts for the recently modified 2008

incentive compensation plans, which are currently in effect and will be in effect when the Commission approves rates resulting from this case. According to AIU, the 2008 plans focus employees on operational metrics and provide a link between pay and performance.

Ms. Bauer explained that there are some similarities between the 2008 plans and the 2006 plans. AIU says the most significant difference between the 2008 and 2006 incentive plans is that payouts for most of the current plans, with the exception of the Executive Incentive Plan for Officers, are no longer funded only if Ameren meets earnings per share ("EPS") targets. Instead, AIU claims performance on incentive key performance indicators (e.g., operational goals) determines whether or not awards will be available under the plan.

AIU argues that even if the Commission does not consider the modified plans, the incentive compensation plans in effect during 2006 are based on the achievement of operational goals that primarily benefit customers; therefore, incentive compensation expense would be properly recoverable regardless of whether the Commission considers the modified plans. AIU asserts that the incentive compensation plans are based on goals such as increased reliability, increased customer satisfaction, increased safety, and improved operational performance. AIU further argues that it has presented the same type of evidence provided in the Docket No. 03-0403 proceeding, where the Commission approved recovery of incentive compensation expense.

AIU contends that Staff's arguments fail to recognize that a high percentage of the expected payouts under the 2008 plans are not tied to financial performance. AIU also disagrees with Staff's argument that a disallowance is appropriate because AIU's incentive compensation plans could be discontinued. According to AIU, incentive compensation is a critical component of AIU's total compensation package. AIU says most companies, including AIU, reserve the right to change, modify, add, or eliminate rewards programs as needed.

Based on the metrics used in either the 2006 or 2008 incentive plan, AIU argues that 100% of AIU's incentive compensation expense should be recovered in rates because the incentive compensation plans are based on metrics that ultimately benefit ratepayers and are part and parcel of a prudent, reasonable, and cost-effective total compensation program.

b. Staff's Position

Staff proposes an adjustment to remove 100% of test year incentive compensation expense from rates. Staff argues that payouts under AIU's incentive compensation plans are dependent upon financial goals of AIU that primarily benefit shareholders. Staff also expressed a concern that ratepayers would provide funding even when no costs were incurred by AIU because the incentive compensation plan goals were not met. Staff contends that the plans are discretionary and may be discontinued at any time. Staff also believes that prior Commission practice supports

the disallowance of AIU's incentive compensation costs from operating expenses. Staff notes that the Commission considered the same incentive compensation plans in AIU's last rate case, Docket Nos. 06-0070/06-0071/06-0072 (Cons.). Although certain financial thresholds have changed in this case, Staff states that the majority of the arguments provided by AIU are nothing more than a replay of the same arguments offered in its last rate case, which the Commission rejected.

Staff points out that AIU indicates that certain revisions were made to its incentive compensation plans effective January 1, 2008, and provided a schedule showing which of the 2006 costs would have been unrelated to financial targets had the revised plans been in place for that plan year. According to Staff, this presentation is flawed for two reasons. First, Staff argues that nothing has been paid out under the revised plans, which will not be considered until the Spring of 2009; thus, Staff believes the impact of the January 2008 revisions is not yet known and measurable. Second, Staff says AIU did not propose an adjustment that limited incentive compensation expense to the costs unrelated to financial targets.

Staff rejects AIU's argument that since the modified plans are those that will be used to determine incentive compensation expense during the period in which rates established in this case will be in effect, it is appropriate to consider the terms of the modified plans. Staff claims this argument is in direct conflict with AIU's position regarding the Public Utility Fund Base Maintenance Contribution. Staff states that in that instance, AIU argues that since the impact of the change in law will not occur until January 2009, it is not appropriate to consider the change in determining the revenue requirements for these cases. Finally, Staff argues, in prior cases the Commission has made clear that it expects utilities to provide detailed information as evidence of ratepayer benefit resulting from incentive compensation plans. Staff believes AIU has not provided this detailed information nor can the information be provided since AIU's revised plans have only been in place since January 2008. As such, Staff contends that the revised plans have not been in existence long enough to provide the type of evidence that must be considered. While AIU asserts that the incentive compensation plans are based on goals such as increased reliability, increased customer satisfaction, increased safety, and improved operational performance, Staff rejects this as detailed evidence the Commission requires. Thus, Staff recommends that the Commission approve its adjustment disallowing incentive compensation costs, a total of $366,000 for AmerenCILCO's gas operations, $567,000 for AmerenCILCO's electric operations, $424,000 for AmerenCIPS' gas operations, $958,000 for AmerenCIPS' electric operations, $468,000 for AmerenIP's gas operations, and $1,135,000 for AmerenIP's electric operations as provided in Schedule 13.07 for each utility.

c. AG's Position

The AG asserts that because AIU's incentive compensation plan results in benefits to shareholders instead of ratepayers, 100% of those program costs should be eliminated from pro forma test year O&M expenses. The AG points out that in more recent cases, the Commission has eliminated incentive compensation plan costs unless

the company can demonstrate that the goals employees are expected to achieve would benefit ratepayers, such as the improvement of service quality, reliability, public safety, reducing absenteeism, and cost containment. The AG states that incentive compensation based on financial goals such as maximizing profitability and growth, increasing EPS, or increasing return on equity is beneficial only to shareholders, and not properly recoverable from ratepayers.

According to the AG, in AIU's last electric rate case, the Commission found that AIU's incentive compensation funding measures all relied on EPS targets and disallowed the entire test year compensation from AIU's revenue requirements. In this case, it appears to the AG that all of the test year incentive compensation expense remains related to the attainment of financial goals. Accordingly, the AG recommends that 100% of the incentive compensation expenses should be eliminated from pro forma test year operation and maintenance expenses. The AG says the effect of this adjustment is to reduce AmerenCILCO's electric expenses by $521,000, AmerenCIPS' electric expenses by $867,000, AmerenIP's electric expenses by $1,027,000, AmerenCILCO's gas expenses by $365,000, AmerenCIPS' gas expenses by $424,000, and AmerenIP's gas expenses by $468,000 as shown on AG/CUB Ex. 1.1, Schedule DJE-4, page 1.

d. CUB's Position

CUB points out that the Commission has disallowed incentive compensation from utilities' revenue requirements except where the utility has demonstrated that the incentive compensation plan provided a tangible, quantified benefit to ratepayers, by reducing expenses and creating greater efficiencies in operations. Therefore, to include any portion of incentive compensation costs in approved operating expenses, CUB says AIU must demonstrate that the plan confers upon ratepayers' specific dollar savings or other tangible benefits.

In the present cases, CUB argues AIU has not presented any such testimony demonstrating its incentive compensation plan confers upon ratepayers' specific dollar savings or other tangible benefits. Accordingly, CUB believes AIU's pro forma operation and maintenance expenses should be adjusted to eliminate the incentive compensation expenses incurred in the test year. CUB contends that because shareholders are the primary beneficiaries of the attainment of AIU's financial goals in terms of increases to earnings and return on equity, it should be those shareholders, not customers, who bear the cost of the incentive compensation related to the achievement of such financial goals.

According to CUB, AIU did not present any evidence that funding measures have changed from the 2004 test year in Docket No. 06-0070/06-0071/06-0072 (Cons.) to the 2006 test year in the present cases. Therefore, CUB argues that it appears that all of the test year incentive compensation expense is still related to the attainment of financial goals. Accordingly, AG/CUB witness Effron proposes to eliminate 100% of the incentive compensation from pro forma test year operation and maintenance expenses.

e. IIEC's Position

IIEC proposes an adjustment to AIU's incentive compensation expense reducing the level of expense included in AIU's cost of service. IIEC asserts that the proposed adjustment should be made to the stakeholder group that benefits from the incentive target, and therefore should pay the related expense. According to IIEC witness Gorman, approximately 50% of the proposed incentive compensation program costs are directly attributable to targets that primarily benefit shareholders. Those targets according to Mr. Gorman include: O&M budget compliance (20%); capital budget compliance (20%); and gas O&M and standards plan development and implementation (10%). IIEC says the remaining program costs are tied to service reliability and employees safety targets. IIEC asserts that AIU confirmed that its test year incentive compensation programs were identical to the programs for which costs were disallowed in AIU's most recent rate case. It was on this basis that Mr. Effron opined that the result in this case should not differ from the Commission's last decision on the same programs. IIEC says AIU's recent program revisions, made to better reflect past Commission decisions, will affect only post-test year incentive compensation plans and costs.

IIEC asserts that upon consideration of the testimony and arguments of Staff and AG/CUB favoring rejection of all incentive compensation costs, and although IIEC finds them compelling, if the Commission is not persuaded and does not disallow AIU's requested incentive compensation costs in their entirety, IIEC's proposes a ceiling for allowed incentive compensation costs. IIEC believes its proposal is consistent with the record evidence and protects ratepayers from those cost burdens that most clearly do not benefit customers.

f. Commission Conclusion

AIU proposes to recover the costs of its incentive compensation plans in rates. AIU argues its new 2008 incentive compensation plans require operational performance to be achieved before payments are made. According to AIU, its operational and individual goals are based on metrics that can be considered and paid independently of financial goals under the plans. AIU claims each of these metrics benefits AIU’s customers by enhancing service, increasing service reliability, and/or increasing the efficiency of operations. Other portions of AIU’s incentive compensation plans retain the EPS funding mechanism. Based on the metrics used in either the 2006 or 2008 incentive plan, AIU argues that 100% of AIU's incentive compensation expense should be recovered in rates because the incentive compensation plans are based on metrics that ultimately benefit ratepayers and are part and parcel of a prudent, reasonable, and cost-effective total compensation program.

Staff proposes an adjustment to remove 100% of test year incentive compensation expense from rates. Staff argues that the incentive compensation plans are dependent upon financial goals of Ameren that primarily benefit shareholders. Staff

adds that ratepayers would provide funding even if no costs are incurred by AIU because the plan goals are not met. Staff states further that the plans are discretionary, may be discontinued at any time and that prior Commission practice supports the disallowance of incentive compensation. Staff also believes that AIU has not provided the detailed information necessary to conclude that ratepayers benefit from the plans. Nor, Staff continues, can such information be provided since AIU's revised plans have only been in place since January 2008. As a result, Staff contends the revised plans have not been in existence long enough to provide the type of evidence that must be considered.

The AG asserts that AIU's test year incentive compensation expense remains related to the attainment of financial goals. Accordingly, the AG recommends that 100% of the incentive compensation expenses should be eliminated from pro forma test year O&M expenses.

CUB argues that AIU must demonstrate that the plan confers upon ratepayers specific dollars savings or other tangible benefits or the costs can not be reflected in rates. According to CUB, AIU did not present any such testimony demonstrating that its incentive compensation plan confers upon ratepayers' specific dollar savings or other tangible benefits. Accordingly, CUB believes AIU's pro forma O&M expenses should be adjusted to eliminate the incentive compensation expenses incurred in the test year.

IIEC asserts that approximately 50% of the test year incentive compensation program costs are directly attributable to targets that primarily benefit shareholders. Those targets, according to Mr. Gorman, include: O&M budget compliance (20%); capital budget compliance (20%); and gas O&M and standards plan development and implementation (10%). IIEC says the remaining program costs are tied to service reliability and employee safety targets.

The Commission is somewhat encouraged that AIU has begun to modify its incentive compensation plans in a manner that may allow it to recover at least a portion of the costs from ratepayers. The Commission is not opposed to the use of employee incentive compensation plans; however, the Commission maintains that before the costs of such plans will be imposed on ratepayers, a utility must demonstrate that the plans provide meaningful benefits to those ratepayers. Regarding AIU's 2008 incentive compensation plan, with the exception of the Executive Incentive Plan for Officers, AIU claims they are no longer funded only if Ameren meets EPS targets. Unfortunately, the record does not specifically identify the portions of the 2008 plan that are directly dependent upon Ameren meeting financial targets.

The record indicates that AIU has in place incentive compensation plans related to safety (weighted 25%), customer service (weighted 10%), and reliability (weighted 15%) that also do not appear to have payouts that are dependent upon Ameren meeting financial targets. In the Commission's view, it is reasonable to allow AIU to pass the cost of these portions of the incentive compensation plans on to customers. Thus, AIU will be allowed to include in operating expense 50% of the total cost of its incentive

compensation expense because the Commission believes that portion provides direct, meaningful benefits to ratepayers and payouts are not dependent upon meeting financial targets that are primarily beneficial to shareholders.

If during the period that the rates approved herein are in effect, however, the incentive compensation plans are revised such that financial goals of Ameren become the payment trigger for a greater portion of the plans, the Commission will not look favorably on incentive compensation expenses in AIU's next rate cases. The Commission is allowing AIU to recover 50% of its incentive compensation expenses with the understanding that at least 50% of the payments made thereunder will based on performance or goals other than Ameren's financial goals.

3. Rate Case Expense

a. Legal Fees

i. AIU's Position

According to AIU, the requested amounts for legal expenses in this case are reasonable. AIU estimates legal expenses for this proceeding as $1,162,000, of which $605,000 was estimated to be incurred by the time hearings began. Through April 30, 2008, AIU asserts that it received invoices for approximately $670,000 for legal expenses. Although rate case expenses were running above budget, AIU states that it is not proposing any upward adjustment to the requested level of rate case expense. AIU argues that the estimated and actual rate case expenses in this case are proving to be reasonable in comparison with actual and estimated costs in the previous rate case.

AIU claims that Staff's assertion that it received invoices "two days prior to the evidentiary hearings," without enough time for Staff witness Ebrey to analyze the invoices contradicts Staff's own statements and testimony. AIU submits that Staff offered no record cites in support of this claim. To the contrary, AIU claims Ms. Ebrey testified at the evidentiary hearing that she had, in fact, reviewed the invoices, again, mentioning her "concerns about a number of the items that appear on the invoices." (Tr. at 791-92) AIU says Ms. Ebrey did not testify, however, that she did not have enough time to review the invoices.

ii. Staff's Position

Staff proposes to limit the cost of legal fees to the amount actually supported by invoices, as AIU did not provide sufficient support for its requested level of legal fees and Staff could not determine the reasonableness of the estimate for those costs. According to Staff, the record in this case only reflects $470,000 in questionable legal fees for rate case expense. Staff characterizes these costs as questionable since it did not receive sufficient detail to be able to analyze the costs until two days prior to the start of the evidentiary hearings. Since no investigation of the costs in question was possible, Staff recommends that the Commission should not allow those costs to be

recovered as rate case expense. In Staff's view, the Commission should only allow the costs for attorney's fees that AIU properly supported.

iii. Commission Conclusion

As the Commission understands it, AIU proposes to reflect in rates approximately $194,000 in legal expenses from the law firm of Jones Day Reavis & Pogue for each utility's electric operations and each utility's gas operations. The Commission also understands that, in contrast, Staff proposes allowing $44,000 for each utility for these costs. Staff proposes disallowing all prospective legal expenses for which invoices were not provided. Additionally, Staff suggests that some invoices provided by AIU were provided so late in the process that Staff was unable to adequately review them. Thus, Staff's proposed disallowance effectively disallows a portion of actual costs incurred for which invoices were provided.

The Commission is troubled by the Staff proposal. The proposal to allow recovery of only legal costs associated with those invoices that Staff has adequately reviewed puts AIU in a situation where it must incur costs but can not recover those costs from ratepayers. There is no question that to effectively pursue this rate increase request, AIU will continue to incur legal expenses after Staff files rebuttal testimony and even after the evidentiary hearings. Obviously, AIU can not produce invoices for Staff to review before the legal work is done. The proposal to disallow 100% of costs for which invoices for rate case legal work that were not adequately reviewed by Staff is fundamentally unfair. A more fair approach might be to propose disallowing the percentage of forecasted costs based upon the percentage of actual legal expenses that were found to be improperly incurred or billed. Other reasonable approaches might be to determine that legal expenses were overestimated by some amount or percentage, or that the legal expenses themselves were unreasonably high. Staff's proposal, however, would inevitably lead to costs that must be incurred but could not be recovered. This is particularly true when combined with Staff's position in this proceeding with respect to unamortized rate case expense, whereby only amounts previously approved by the Commission are eligible for recovery on a prospective basis. Staff's approach would be an unfair and unreasonable result. Based upon the record in this proceeding, the Commission hereby rejects Staff's proposal to disallow legal costs associated with these rate cases.

b. Gannett Flemming Costs

i. AIU's Position

Gannett Flemming, a consulting firm hired by AIU, prepared a depreciation study for AIU in this proceeding. AIU states that Staff witness Ebrey accepts its rebuttal position for the costs of the depreciation study; however, AIU claims she fails to take into account invoice updates provided for March and April that include an additional $25,000 in post filing support. It is AIU's position that Ms. Ebrey only accounted for $20,000 of actual post filing support, for only two months of work – January and

February 2008. According to AIU, it incurred $45,000 of actual post filing support through April compared to Staff's $42,000 proposal meant to cover the entire post filing cost. AIU contends that considering the electric depreciation study remains contested and that total post filing support costs through April are 41% of the total proposal ($45,000 / $111,000 = 41%), AIU requests post filing support in the amount of $25,000 per electric utility and $12,000 per gas utility, and complains that Ms. Ebrey only proposes allowing $10,000 per utility for post filing support.

ii. Staff's Position

Staff accepts AIU's levels of reduced costs for the depreciation studies; however, Staff says it is unable to accept AIU's cost projection for costs associated with post-filing support proposed by AIU for either the gas or electric utilities. Staff maintains that AIU has not shown the actual costs estimates from Gannett Fleming. AIU, according to Staff, provided only the total amounts included as rate case expense and did not provide any tracking of actual costs. Staff says that based on invoices received from AIU, an average of $3,400 per utility (a total of just over $20,000) has been expended for post-filing support of the depreciation studies. Staff's proposal allows an additional $7,000 per utility, or a total of $42,000, for post-filing support for the depreciation studies. Given the level of post-filing support reviewed by Staff at the time of rebuttal testimony, Staff's contends its proposal is reasonable. In its reply brief, Staff explains that it proposes allowing an additional $17,000 to cover costs for May through the end of the hearings that is in addition to the $45,000 in costs incurred from November through April that Staff says is supported by invoices.

iii. Commission Conclusion

Although it is not entirely clear, it appears that AIU is proposing to recover $39,000 from each utility's gas customers and $35,000 from each utility's electric customers while Staff is proposing AIU be allowed to recover $37,000 from each utility's gas customers and $20,000 from each utility's electric customers. Again, while not entirely clear, it appears that the reasons that AIU and Staff disagree about the level of Gannett Fleming costs that should be passed on to ratepayers relates to invoices for March and April, 2008 as well as the level of estimated costs that had not been incurred at the time Staff took its final position. Consistent with its conclusion immediately above regarding legal expenses, the Commission rejects Staff's proposal to exclude from operating expenses costs attributable to Gannett Fleming that have not yet been incurred. Of the proposals in the record, AIU's estimate of the costs is the most reasonable and is hereby adopted.

c. Energy Efficiency Witness

i. AIU's Position

AIU understands that Staff recommends disallowing the entire cost of AIU's energy efficiency expert witness in this case, Mr. Hanser, based on Staff's belief that the

expert witness was hired to provide testimony that does not relate to this rate case. AIU argues that energy efficiency and Mr. Hanser's testimony do directly involve AIU's rate cases and the setting of rates. According to AIU, Mr. Hanser's testimony was an essential component of explaining the Rider VBA proposal. He also testified regarding the programs implemented by other utilities in the Midwest, expenditures directed to such programs, and appropriate spending levels. According to AIU, energy efficiency initiatives directly affect cost recovery, and AIU would only pursue such programs contingent upon approval of Rider VBA. Lastly, AIU argues, without this direct testimony filing, its rate case presentation would have been deficient. Thus, AIU contends the energy efficiency rate case testimony costs are prudently incurred, and should be allowed.

ii. Staff's Position

Staff recommends disallowing all costs proposed by AIU for its energy efficiency witness since, according to Staff, Mr. Hanser's testimony does not relate to the setting of base rates, the subject of the rate cases, but rather discusses energy efficiency programs, their merits, and associated costs. Staff notes that these topics are directly related to the current Docket No. 08-0104, in which AIU petitioned the Commission for approval of the natural gas energy efficiency plan and the associated Rider GER.

iii. Commission Conclusion

The Commission understands that AIU has the burden to prove its case in any rate proceeding, and in order to efficiently accomplish such a task must make judgment calls of what type of witnesses will be needed to present its case to making a proper showing supporting its proposals. The Commission believes it is unlikely that AIU retained services from an expert that AIU believed was not needed. The Commission takes into consideration various factors that come into play in any case, such as preparing a witness, preparing direct examination and reviewing the expert analysis and reports, and meeting with the expert throughout the case. It does not seem logical to the Commission that AIU would retain an expert that it believed it did not need in support of its case. Whether the Commission approves Rider VBA is not relevant, as AIU has the right, and arguably the obligation, to support any proposal it makes in a rate case. AIU's argument that Mr. Hanser was retained in support of Rider VBA is logical. Therefore, the Commission believes the costs for the energy efficiency witness should be allowed and Staff's proposal to remove the costs from operating expenses is hereby denied.

d. Unamortized Rate Case Expense / Amortization Period

i. AIU's Position

AIU asserts that the AG/CUB's recommendation to disallow unamortized rate case expense is essentially asking the Commission to reverse its prior order approving the amortization of costs incurred in association with Docket Nos. 06-0070/06-0071/06-

0072 (Cons.). AIU argues this is inappropriate because such an adjustment would deny AIU the opportunity to recover its Commission approved, prudently incurred costs.

AIU asserts that because it expects to be filing rate cases on a 2-year schedule in the foreseeable future, it proposes to amortize this rate case expense over a two-year period. AIU notes that Staff proposes a 5-year amortization period for gas rate case expense and a 3-year amortization period for electric rate case expense. According to AIU, Staff's proposed amortization periods are too long, and unreasonable in order for AIU to recover gas and electric rate case expense. AIU submits that it has never been on a 5-year rate case filing schedule and AIU argues that facts and issues have changed for both gas and electric delivery systems since the last rate cases were filed. AIU suggests that costs and other rate inputs have become increasingly volatile. AIU further argues that there are several factors influencing AIU's authorized return as well as system improvements that will continue into the future. AIU asserts it is committed to increasing improvements to the electric distribution system infrastructure. These issues, according to AIU, will fuel the need to file rate cases on a more frequent basis. Thus, AIU believes its proposed 2-year amortization period for both gas and electric rate case expenses is reasonable under current and expected circumstances and should be approved.

ii. Staff's Position

Staff recommends an adjustment for rate case expense of $259,000 in operating expenses for each gas utility and $215,000 in operating expenses for each electric utility reflecting the inclusion of unamortized rate case expense from prior rate cases. These proposed adjustments reflect Staff's recommended amortization periods of 3 years for the electric utilities and 5 years for the gas utilities. Staff claims these periods are based on time periods between prior rate case filings.

Staff suggests that its proposed amortization periods are consistent with the time periods between the effective dates of the most recent rate changes of AIU. According to Staff, AIU's proposal to recover rate case expense over a 2 year amortization period for both the gas and electric utilities is a rather aggressive amortization period since it will have been 5 years since the current AmerenCILCO and AmerenCIPS gas rates have been in effect and 3 years since the current AmerenIP gas rates have been in effect when the rates in the instant proceedings become effective. According to Staff, while the 2 year period is representative for the time since the last electric rates were set, a 2 year period is shorter than any rate case amortization approved by the Commission in recent history. Staff argues that there is a risk involved with setting a shorter amortization period versus having a longer amortization period, noting that if the amortization period is less than the period rates are in effect, AIU would recover more than the Commission-approved rate case expense. Staff opined that the ratepayers would then bear the risk with no risk to the shareholders of under recovery.

Staff argues that its recommendation is consistent with AIU's pro forma adjustments for rate case expense in these proceedings, which include a component for

unamortized rate case expense. Staff points out that AIU offered no rebuttal to Staff witness Ebrey's discussion regarding the risks involved with a shorter amortization period for rate case expense.

iii. The AG and CUB's Position

The AG and CUB argue that AIU's proposed amortization of prior rate case expenses should be rejected because it allows AIU to over-recover its rate case expenses. According to them, the purpose of including the normalized rate case expense in the cost of service is not to guarantee a dollar-for-dollar recovery of the rate case expense incurred, but rather to allow a reasonable opportunity to recover the cost of the rate case by including what is deemed to be a "normal" rate case expense in the cost of service. The AG and CUB assert that the problem occurs when the actual period between rate cases is different than that assumed in calculating the amortization of rate case expenses. Thus, they recommend eliminating the amortization of the prior rate case costs from the revenue requirement in these cases, which will then reduce AmerenCILCO electric expenses by $570,000, AmerenCIPS electric expenses by $570,000, AmerenIP electric expenses by $570,000, AmerenCILCO gas expenses by $170,000, AmerenCIPS gas expenses by $101,000, and AmerenIP gas expenses by $303,000.

iv. Commission Conclusion

The Commission rejects AIU's proposed two-year amortization period for rate case expenses. From a historical perspective, this is simply too short of a period. While it is true that in the recent past AIU's gas electric rate cases have been relatively frequent, there have been periods lasting almost a decade or more in which the utilities did not request a rate case. The Commission is not certain when the trend of relative frequent rate cases will change, but it fully expects it to happen. Contrary to AIU's suggestions, the regulatory environment is not so changed that it warrants a two-year rate case amortization period. The Commission agrees with Staff that there is a risk to the ratepayers of overpayment if AIU's proposal were adopted. The Commission therefore adopts Staff's proposal to utilize a five-year amortization period for gas rate case expenses and a three-year amortization period for electric rate case expenses.

As for the AG and CUB's proposal to totally exclude from rates the unamortized rate case expenses approved in AIU's last rate, the Commission rejects this proposal. Contrary to their argument, the Commission does not establish a "normal" level of rate case expenses as it does for other types of cost that are prone to variation over time. Instead, the Commission typically allows a utility to capitalize those costs and amortize them over some reasonable period of time. The AG and CUB proposal would deny AIU the opportunity to recover reasonable, prudently incurred costs. To the extent AIU was authorized to recover rate case expenses in its last rate case and there remain unamortized balances of such authorized costs, AIU will be allowed to reflect such costs in rates in this proceeding.

e. Navigant, Concentric Costs

i. AIU's Position

AIU points out that Staff raises several arguments regarding AIU's rate case expense costs relating to Navigant and Concentric. According to AIU, while Staff accepted all expenses invoiced by Navigant, Staff questions the level of the Navigant and Concentric costs leading up to AIU's rate case filing and, according to AIU, generally disregards the supporting facts that costs associated with the Navigant invoices were actually incurred, prudent, and reasonable.

Staff witness Ebrey claims that certain costs associated with Concentric would not have been incurred if AIU had not switched consulting firms from Navigant to Concentric. AIU argues it did not incur additional costs by continuing to work with their expert witness, Mr. Adams, after he left Navigant and began work for Concentric on July 1, 2007. AIU claims that estimated costs of post-filing services increased in October 2007, several months after Mr. Adams switched to Concentric. At that time, AIU explains it reexamined the scope of work requested from Mr. Adams, and determined that AIU would need significantly more post-filing assistance from Mr. Adams than previously anticipated.

AIU asserts that Staff's hypothesis fails to take into account that if the AIU had continued to use Navigant after Mr. Adams had switched firms, they would have been forced to switch their chosen expert witness, who was retained for his experience, knowledge, and familiarity with AIU's operations and business.

AIU also points out that Staff raised concerns regarding a paid Navigant invoice marked "Do Not Bill." According to AIU, Staff disregards its explanation that the notation "NB Do Not Bill To" was an error on the part of Navigant. AIU argues that it should not be penalized for a mistake on a vendor's invoice. In support of this proposition, AIU argues that as Manager of Regulatory Accounting, Mr. Weiss explained that he reviewed the invoice and determined that the total hours billed and the summary hours listed by the consultant was reasonable.

AIU contends that it provided Staff with the Concentric invoices supporting the lead lag study totaling $100,000, compared with the original budgeted amount of $130,000. Thus, actual costs are in line with estimates. AIU also contends that it provided invoices supporting the AMS market study totaling $653,000 compared to the original budgeted amount of $750,000. AIU accepts the lower amount and applies it to the updated rate case expense.

AIU asserts that while Staff concedes the increased level of complexity associated with rate filings, Staff does not fully appreciate that with increased complexity comes increased costs. AIU witness Wichmann testifies that the discovery process in these rate cases has been far more exhaustive than in the last delivery service rate cases. He states that the post-filing support estimate was increased with

the expectation that Concentric would need to budget for a significant increase in time and expense due to the higher level of complexity in the rate filing and testimony provided with the filing, which AIU says was borne out through substantial additional support for unanticipated issues, including the proposed plant addition disallowances.

ii. Staff's Position

Staff recommends reducing the amount of costs for the Navigant/Concentric consultants by a total of $270,000 (from $429,000 to $385,000 for each gas utility and $401,000 to $355,000 for each electric utility). According to Staff, a review of the support provided for Navigant/Concentric costs raises a number of concerns. Staff argues there is a potential conflict of interest for the review and approval of certain charges for payment. Specifically, the conflict of interest issue concerns charges by the consultant who is the son of the Manager of Regulatory Accounting at AMS, the individual to whom the invoices from Concentric and from Navigant are addressed. According to Staff, in most cases, the Manager of Regulatory Accounting signs off that the bills are "OK" to pay. Staff submits that the conflict of interest allowed costs that should not have been paid by AIU as rate case expense for recovery from ratepayers. These costs include entertainment costs, sick pay, incorrect hotel charges, and other travel expenses. There were also billing errors that were not adequately explained, and transition period costs from Navigant paid by AIU. Staff also noted inconsistent and increased billing rates during the duration of the consultation; and budgeted costs for specific projects above amounts expended. Based on these concerns, Staff recommends that the amount of rate case expense associated with Navigant/Concentric consultation be set at $385,000 for each gas utility and $355,000 for each electric utility.

Staff recommends that the Commission order AIU to perform an internal study of all instances in which an individual who is responsible for the approval of charges for payment has conflicts of interest with the individuals performing the work or receiving payment for the work. Staff says the Commission should further order AIU to institute safeguards to minimize the future occurrence of instances that raise this conflict of interest, and to report to the Commission the safeguards that are implemented with a copy to the Manager of Accounting within six months of the date of the order in this proceeding.

iii. Commission Conclusion

With regard to the alleged transition costs attributable to Navigant/Concentric, there is no dispute that Mr. Adams changed firms. At that time, AIU believed that it needed to continue its relationship with Mr. Adams to support its rate cases, which the Commission believes to be a reasonable conclusion. Having said that, however, it seems logical that AIU would have to incur additional costs to retain two consulting firms for a period rather than one, as well as to coordinate and administer the activities of two consulting firms rather than one.

With regard to the alleged conflict of interest, AIU attempts to dismiss the possibility by alleging that the AIU employee at issue was not actually approving the costs in question but that it was AIU's attorneys approving the costs. Given the circumstances, AIU's explanation is not convincing. The Commission, however, does not see a need to require AIU to perform an extensive analysis of potential conflicts of interest and report back to the Commission. The Commission simply directs AIU to ensure that such potential conflicts do not occur again and to avoid the appearance of impropriety. If such a situation arises again, any associated expenses will not be viewed favorably to AIU.

AIU claims that it should not be penalized when a vendor incorrectly bills it; however, Staff has raised legitimate concerns about billing errors that the Commission is unable to fully resolve. As a result of the legitimate concerns raised regarding Navigant/Concentric billing issues, the Commission finds Staff's proposed disallowances to be reasonable and they are herby adopted.

4. Uncollectibles Expense

a. AIU's Position

AIU proposes that the Commission determine the uncollectible percentage for each utility using a 3-year average of 2005-2007 net write-offs divided by revenues. AIU argues that the Commission should exclude historical data from 2003 because the use of that data would understate the uncollectible percentage and unfairly distort the uncollectible expense levels. According to AIU, the data shows an upward trend in net write-offs since 2003. For each of the electric utilities, AIU indicates that net write-offs are highest in 2007. For two of the three electric utilities net write-offs are lowest in 2003. For two of the three gas utilities, the highest net write-offs are in 2006 and the lowest in 2003. AIU submits that this upward trend demonstrates that the most weight should be placed on the most recent data.

b. Staff's Position

Staff proposes a 5-year average of net write-offs as a percentage of revenues consistent with the time period used in the most recent prior AIU rate cases, Docket Nos. 06-0070/06-0071/06-0072 (Cons.). Staff disputes the claim by AIU that its proposed 3-year average for net write-offs is more representative than the 5-year average proposed by Staff. Staff argues that AIU offers neither any explanation for the increased level of net write-offs experienced in 2007, nor any evidence that the same level of net write-offs will continue into the future. Staff states that the data presented by AIU does indicate, however, that the level of net write-offs fluctuates over time, necessitating the normalization approach.

Staff's proposed adjustment to uncollectibles expense and the uncollectibles rates to be used for each utility based on the 2003 through 2007 net write-offs also removes the impact of Section 16-111.5A(f) of the Act in the 2007 revenues booked by

AIU. AIU witness Stafford claims that Staff‘s adjustments to 2007 revenues are inappropriate since Staff did not establish that the 2007 adjustments are unique or provide any supporting analysis to demonstrate that no other adjustments should be made for other variances.

Staff recommends the Commission approve its proposed adjustment to uncollectibles expense and the uncollectibles rates to be used for each utility based on the 2003 through 2007 net write-offs, including the adjustment removing the impact of Section 16-111.5A(f) of the Act, on the 2007 revenues booked by the utilities.

c. CUB's Position

CUB recommends that pro forma test year uncollectible accounts expense be normalized based on the average of net-write-offs to revenues for the 3 years 2005-2007. CUB's recommendation was adopted by AIU.

d. CNE-Gas' Position

CNE-Gas recommends that the Commission require AIU to exclude transportation customers from the recovery of uncollectible commodity costs. CNE-Gas argues that AIU recovers natural gas commodity-related uncollectible expense through the gas delivery service rates of both system and transportation customers. However, CNE-Gas believes the Commission must direct AIU to eliminate commodity-related uncollectible recovery from transportation customers. In support of its recommendation, CNE-Gas argues it is unfair for transportation customers to pay for uncollectible commodity costs to AIU, which does not supply gas to transportation customers. CNE-Gas argues that given recent Commission precedent and the inequity of AIU's charging transportation customers for purchased gas costs, the Commission must require AIU to remove the recovery of uncollectible commodity-related costs from its transportation rate schedules.

e. AG's Position

The AG argues that in order to ensure that the pro forma adjustment accurately reflects actual experience, the pro forma test year uncollectible accounts expense should be normalized based on the average of net-write-offs to revenues for the three years 2005–2007. The AG indicates that AIU ultimately agreed with it on this proposal, making a minor modification that the AG does not dispute.

The AG also argues that the gross revenue conversion factor should be modified so that the revenues used in the denominator are consistent with expenses used in the numerator. According to the AG, AIU includes the effect of uncollectible accounts in its calculations of the Gross Revenue Conversion Factors used to convert the calculated income deficiencies into the required additional revenues, in effect recognizing the additional uncollectible accounts related to the proposed rate changes. In calculating the uncollectible accounts rates to be used in the gas Gross Revenue Conversion

Factors, according to the AG, AIU took the ratio of total uncollectible accounts to gas delivery service revenues excluding purchased gas revenues. The AG argues that this results in a mismatch which overstates the uncollectible expense rates to be included in the gas Gross Revenue Conversion Factors applicable to gas delivery service. The AG submits that the uncollectible accounts rates included in the Gross Revenue Conversion Factors should be modified so that the revenues used in the denominator are consistent with the expenses used in the numerator. The appropriate gas Gross Revenue Conversion Factors, according to the AG, are 1.146%, 1.226%, and 0.937% for AmerenCILCO, AmerenCIPS and AmerenIP, respectively, as compared to AIU's proposed uncollectible accounts rates of 5.766%, 4.582%, and 6.116%, respectively.

f. Commission Conclusion

AIU, CUB, and the AG propose that the Commission determine the uncollectible percentage for each utility using a 3-year average of 2005-2007 net write-offs divided by revenues. AIU argues that the Commission should exclude historical data from 2003 because the use of that data would understate the uncollectible percentage and unfairly distort the uncollectible expense levels. Staff proposes a 5-year average of net write-offs as a percentage of revenues. Staff disputes AIU's claim that its proposed 3-year average for net write-offs is more representative than the 5-year average proposed by Staff. Thus, Staff recommends a proposed adjustment to uncollectibles expense and the uncollectibles rates to be used for each utility based on the 2003 through 2007 net write-offs.

It appears to the Commission that historical data from 2003 understates the uncollectible percentage and unfairly distorts the expense. It also appears that, generally speaking, there is an upward trend in AIU's uncollectibles. Therefore, the Commission finds that the proposal to use a three-year average of 2005-2007 net write-offs divided by revenues is reasonable and should be adopted.

The AG argues that AIU overstates the uncollectible expense rates to be included in the gas Gross Revenue Conversion Factors applicable to gas delivery service. The Commission finds that the AG's argument in regards to the Gross Revenue Conversion Factor issue is misplaced. The Commission has considered the level of uncollectibles authorized in this Order when establishing the appropriate Gross Revenue Conversion Factor used to calculate AIU's revenue requirements in this proceeding.

CNE-Gas recommends that the Commission require AIU to exclude transportation customers from the recovery of uncollectible commodity costs. CNE-Gas argues that AIU recovers natural gas commodity-related uncollectible expense through the gas delivery service rates of both system and transportation customers. CNE-Gas argues it is unfair for transportation customers to pay for uncollectible commodity costs to both AIU, which does not supply gas to transportation customers, and the transportation customers' suppliers. It appears that no party objects to CNE-Gas' proposal. The Commission finds CNE-Gas' proposal to exclude system and

transportation customers from the recovery of uncollectible commodity costs to be fair and reasonable, it is therefore adopted.

5. Injuries and Damages Expense - AmerenIP

a. AIU's Position

AIU agrees with Staff witness Ebrey's proposal to normalize injuries and damages expenses over a 5-year period for AmerenIP, but has rejected what it describes as her subjective "hybrid" normalization approach. AIU argues that its normalization calculation appropriately includes all of the AmerenIP electric 2005 actual payments in the injuries and damages expense calculation. AIU contends that the result of this calculation is fair and consistent with the methodology previously approved by the Commission, and results in a true "normal" expense level as reflected in Ameren Ex. 20.7.

AIU argues that while Ms. Ebrey purports to use the same methodology to normalize injuries and damages expense that was approved by the Commission in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), she in fact does not. In that case, AIU claims the Commission approved a 5-year average of AIU's injuries and damages expenses. According to AIU, Ms. Ebrey appears to combine this normalization methodology with the one approved by the Commission in Docket Nos. 07-0241/07-0242 (Cons.), where the Commission approved the utilities' actual test-year expenses, adjusted for a highly unusual credit recorded in a prior year. Thus, Staff combines these two different methodologies to produce what AIU believes is an unfair result, by both normalizing and removing costs.

According to AIU, Staff's approach is not reasonable because the point of normalizing is to flatten out the peaks and valleys of a volatile cost component, by averaging actual costs over a reasonable time period. In this case, AIU argues that Staff has subjectively chosen to remove certain costs from this average, which does not result in an accurate "normal" calculation. AIU's proposed cost level averages actual costs over a 5-year period, which according to AIU is a reasonable period of time over which to account for the highs and the lows. AIU also notes that Ms. Ebrey does not claim that AIU's proposed injuries and damages expense level is unreasonable or does not reflect a "normal" amount.

According to AIU, Ms. Ebrey claims that the issue hinges on whether the costs she chose to remove from the 2005 payouts are "extreme and unusual." AIU argues that this argument misses the point because AIU considers all injuries and damages to be unusual. There is no "normal and expected" accident which, according to AIU, is why injuries and damages are a volatile cost component. AIU maintains that normalizing flattens out the highs and lows of "extreme and unusual" costs, by averaging actual costs over a reasonable time period.

b. Staff's Position

Staff proposes an adjustment to injuries and damages expense for AmerenIP's electric operations that removes consideration of the extraordinary claims included in the 2005 payouts from the calculation of a normalized amount. Staff claims AIU offered no evidence refuting Staff's position that the claims removed from the 2005 payout level were extreme and unusual. Staff states that AIU witness Wichmann was unable to confirm whether or not the type of, as well as the dollar magnitude of, the claims excluded by Staff were likely to occur annually. Thus, according to Staff, the 2005 claims that are outside the routine level and type of injuries and damages expense are appropriately excluded for the calculation to normalize AmerenIP's electric utility injuries and damages expense. Staff recommends that the Commission adopt Staff's adjustment of $2,654.000 to AmerenIP injuries and damages expense of electric operations.

c. Commission Conclusion

While AIU correctly suggests that it is reasonable to expect injuries and damages expenses to fluctuate from year to year, given the nature and magnitude of the 2005 AmerenIP injuries and damages expenses, this does not appear to be a routine variation. The Commission finds that the injuries and damages expense that occurred at AmerenIP during 2005 is unusually high and should be considered an outlier. The Commission, however, does not agree with Staff's approach to dealing with this unusual situation. By adjusting the 2005 figure and including it in the 5-year average, the Commission observes that Staff changed the 2005 value from the highest of the 5 into the lowest. The Commission believes the superior approach in this situation is to remove entirely the 2005 injuries and damages from the calculation. Based on this conclusion and using the information on Staff Ex. 1.0, Schedule 1.11 IP-E, the Commission effectively finds that the injuries and damages expense for AmerenIP should be based upon the average of 2003, 2004, 2006, and 2007.

6. Energy Toolkit

a. AIU's Position

AIU has proposed recovering the cost of its Energy Toolkit in the operating expense level for each of its utilities. AIU claims that the Energy Toolkit is a unique program that stands on its own merits and would be of value to customers, however, if the Commission does not approve recovery of the costs for this available program as Staff suggests, AIU will have no alternative but to discontinue the program.

While AIU agrees with Staff that there are other sources of information that may assist customers in better understanding and managing their energy costs, AIU avers that there is no other available site that has the capability of automatically loading, storing and analyzing individual customer usage. AIU opines that there is no other site that allows the customer to complete an individualized energy analysis audit based on

AIU's metered usage, area weather, billing cycle data, changes to owned appliances, and individual lifestyle, and then integrates these pieces of customer-specific information in a format that allows a typical AIU residential customer to better understand and manage their energy expenses.

AIU notes that while Staff witness Ebrey researched similar energy efficiency programs on the internet, she did not identify any site that contained the same information as found in the Energy Toolkit. Ms. Ebrey claims she reviewed a number of sites that had information of the type found in the Energy Toolkit. AIU opines that Staff appears to view the Energy Toolkit as being synonymous with any internet site or program related to energy efficiency. AIU submits that Staff's misunderstanding could be due to the fact that many energy efficiency programs have the same goal or objective and provide information and education to customers in an effort to meet this goal. AIU argues that the Energy Toolkit is a unique service that complements the approved programs and is not duplicative of other internet sites.

AIU claims that the Energy Toolkit would even provide benefits to customers that do not have access to the internet. AIU witness Martin states the Energy Toolkit contains functionality that would act as an enhancement to AIU's customer information system. He says this functionality allows call center agents to provide much of the same information and analysis to residential customers contacting AIU via phone just as if the customer accessed the toolkit on the web. The call center agent interface to the Energy Toolkit, AIU claims, allows the agent to assist with an energy audit, explain monthly, seasonal or annual changes to price and usage experienced by a customer. The Energy Toolkit, AIU contends, will also allow the agent to generate and mail a customized report to the caller, and would allow customers that contact AIU by phone to receive much of the same energy analysis information.

AIU asserts that the Energy Toolkit not only provides education and information about energy efficiency, but may also be used by AIU customers or call center agents to understand many aspects of their utility bill including effects of price, metered usage, weather, and billing cycle. The Energy Toolkit, AIU argues, is a single site that will be deployed specifically for AIU gas and electric customers that gathers data and information from a variety of sources, synthesizes the data into a meaningful format, and presents this customer-specific data in a manner that simplifies the process of understanding, comparing, and managing their energy expenses. AIU says the Energy Toolkit costs will not be recovered through Rider EDR.

AIU believes that the Energy Toolkit provides value to its customers by providing customers an informational and educational resource and that enables them to make informed decisions regarding their energy usage. For a customer to try to similarly self-educate, AIU argues, would be extremely difficult, and would require a significant amount of research, time, effort, and analysis. AIU claims the information the Toolkit provides has the potential to save customers significant amounts off of their energy bills over time, depending on the customer and on individual choices. In summary, AIU

believes the Energy Toolkit program provides meaningful ratepayer benefits, thereby justifying recovery of the costs of this program in rates.

b. Staff's Position

Staff recommends an adjustment to disallow costs for the Energy Toolkit because, according to Staff, the new program does not provide any additional benefit or information to AIU's customers that is not already available through other sources, and it is not necessary for the provision of safe and reliable utility service. Staff argues that the program is not as unique as AIU claims. Ms. Ebrey, after referring to a number of similar web sites, indicates she found many sites that required similar AIU customer specific information to be input that would also generate customer specific billing information on energy usage.

Staff maintains that no measurable added value to customers has been identified by AIU. Staff disagrees with AIU's claim that there is value inherent in making the tool available to its customers as an informational and educational resource that might allow customers to make informed decisions regarding their energy usage. Staff opines that this informational and educational resource is simply a different delivery mechanism for information and education that is already planned under the Energy Efficiency Demand Response Plan. Staff argues that it is unreasonable for ratepayers to bear the cost for this duplication of information. Staff thus recommends a $275,233 adjustment disallowing AIU's pro forma adjustments for the Energy Toolkit.

c. Commission Conclusion

The Commission believes that AIU's Energy Toolkit can assist ratepayers in making decisions and taking actions to improve energy efficiency, reduce energy usage, and ultimately lower their utility bills. While some of the information provided through the Energy Toolkit is available through other resources, the Energy Toolkit is very detailed and personalized for each individual customer. Taking into consideration the relatively modest cost of the program, the Commission finds that the Energy Toolkit program provides customers an excellent opportunity to reduce their energy usage and that therefore the associated costs should be reflected in AIU's rates. In order to ensure that customers are aware of the Energy Toolkit, the Commission directs AIU to periodically include information about the availability of the Energy Toolkit in its bill inserts (if it is not already doing so).

7. Collateral and Prepayments

a. AIU's Position

AIU believes it should be allowed to recover the costs associated with prepayment and collateral posting for gas purchases. AIU claims such additional costs are necessary and will remain necessary unless and until AIU carries investment-grade ratings. AIU says that for gas operations, a cost of providing service is the requirement

that utilities either prepay for certain services or post collateral. Such a requirement, AIU asserts, is due to limited access to unsecured credit, primarily driven by AIU's below-investment grade credit ratings.

AIU insists that cash collateral and prepayments increase the costs of providing gas. For cash collateral postings, AIU says the cost is estimated by finding the monthly negative carry and multiplying by the monthly amount of the collateral postings. AIU states that the negative carry is estimated as the difference between the actual short-term borrowing rates in effect for AIU each month and the actual Federal Funds Target Rate in effect each month. The Federal Funds Target Rate is the rate of interest often received for cash balances posted to counterparties. For prepayments, AIU says it does not receive interest, as prepayments are considered early payment for pending deliveries rather than as cash deposits that are being held over time. Therefore, AIU says the cost of prepaying is estimated by multiplying the actual short-term borrowing rates in effect each month for AIU by the monthly amount of prepayments.

According to AIU, prepayment requirements and collateral postings to assure performance most often arise under North American Energy Standards Board ("NAESB") agreements or International Swap Dealers Association ("ISDA") agreements with various counterparties. Because AIU's ratings are below investment grade, it says many of its respective NAESB and ISDA counterparties have availed themselves of a contractual right to require the posting of performance assurances. In AIU's view, it is reasonable to expect that many counterparties to these agreements will likely continue to seek to be fully secured with respect to any positive exposure it has until AIU's ratings return to investment grade levels. AIU says if it were to fail to provide prepayment as contractually required, it could be cited for default and could be at risk in its efforts to secure and maintain stable, long-term gas supplies for its ratepayers.

Depending on the circumstances, upon receipt of a request for prepayment, AIU claims it could need to provide prepayment on the same day or on the next business day. Within many of the agreements to which AIU is principal, it says calculations of credit exposure take place daily. In instances where a counterparty calculates exposure to AIU that exceeds any unsecured credit to which AIU is entitled, AIU claims the counterparty would have a contractual right to require a margin posting. Such calculations and margin calls can, and often do, take place each business day. In most cases under ISDA contracts, AIU says counterparties have one business day to post the margin as requested. As is a standard practice within the energy industry, AIU says it performs the same calculations as its counterparties: (1) in order to determine the appropriateness of any margin call received by AIU; (2) to determine whether margin posted by AIU should be returned; and (3) to determine whether AIU should request margin from any of its respective counterparties.

AIU claims that the amounts of cash collateral and prepayment can change monthly or more frequently and are susceptible to change as often as daily. AIU says prepayment amounts may change monthly or more frequently, depending upon the nature of the agreement and whether the transaction is base load or swing. Under a

monthly base load contract, AIU states that the prepayment amounts can vary due to varying estimated monthly volumes and varying prices applicable to the volumes. Under swing packages, AIU says it may exercise a right to call on variable amounts of gas depending upon the need that exists at that time, and prepayment would vary according to gas volumes and pricing. With respect to cash collateral, AIU indicates the amounts may change daily, depending on the nature of each agreement and the transactions executed under each agreement.

AIU claims that if it carried investment grade ratings, in most instances it would be able to pay for gas supplies during the month following the receipt of gas deliveries, which would substantially reduce and possibly eliminate prepayment-related costs currently borne by AIU. AG/CUB witness Effron reviewed the collateral and prepayment costs as estimated by AIU in response to AG Data Request 4.13. He proposes modifications to the prepayment cost amounts estimated by AIU, indicating: (1) AIU excludes the prepayment balances in the first available month in which data was available; and (2) he recommends the latest known applicable interest rate be used rather than the month-by-month interest rates. In addition, Mr. Effron's Schedule DJE-4, page 4, indicates he is averaging the individual monthly amounts of prepayment postings to obtain an average monthly prepayment posting to which he then applies the most current annual rate of interest. In surrebuttal, AIU witness Moloney concludes that the methodology used by Mr. Effron to calculate his proposed "Annual Interest" amounts (AG/CUB Ex. 4.1, Schedule DJE-4, page 4) is acceptable. The "Annual Interest" reflected in AG/CUB Ex. 4.1, Schedule DJE-4, page 4 is as follows: AmerenCILCO ($353,000); AmerenCIPS ($76,000); AmerenIP ($672,000).

Staff witness Ebrey recommends a disallowance of AIU's pro forma adjustments to include as purchased gas expense an interest component related to cash collateral and prepayments. She bases the adjustment on her claim that AIU has not shown that these collateral postings and prepayments are solely for purchased gas. Ms. Ebrey also claims that, if the collateral posting and prepayments are solely for purchased gas costs, they would be considered for recovery through the rates determined under the PGA clause, rather than recovery through base rates.

AIU states that Ms. Ebrey opines that prepayments could be reflected in a CWC analysis and AIU believes this makes sense. AIU says that in such an analysis, the Commission takes into account expense leads, or how many days between when a utility acquires goods or services and when it must make a cash payment. According to AIU, with a prepayment, the lead goes from positive to negative. AIU states that instead of, for example, 4 weeks after receipt, a utility might have to pay 2 weeks before receipt. AIU claims this 6 weeks' difference makes a difference to the utility, in that it represents 6 weeks of carrying cost on the cash.

In AIU's view, the evidentiary record supports the following options for recovery of the carrying cost of collateral: through the revenue requirement; recovery through the PGA mechanism; or as a line item in rate base. For the carrying cost of prepayments,

AIU says the record supports recovery either through the revenue requirement, as a component of CWC, through the PGA mechanism, or as a line item in rate base.

b. Staff's Position

According to Staff, the financing costs of prepayments or interest are a component of a utility's cost of capital. Staff claims the interest expense associated with prepayments has not historically been considered an allowable operating expense in revenue requirement development. To the extent that the gas purchases have been included in storage gas included in rate base and a utility's cost of capital reflects the manner in which a utility finances rate base assets, Staff argues that the revenue requirements capture utility interest requirements. AIU claims that the carrying costs of the prepayments which are on the balance sheet of AIU are the costs on which AIU seeks a return. Staff claims that AIU witness Wichmann admitted that no such costs are specifically identified on the AIU balance sheets and that AIU did not actually transfer funds to pay interest, or carrying costs, associated with the financing of prepayments. (Staff Initial Brief at 171-172, citing Tr. at 734 and 737) According to Staff, those carrying costs are not actual out-of-pocket costs associated with gas purchases and therefore recovery would not be allowed through the PGA.

According to Staff, AIU claims that Ms. Ebrey suggests that AIU's CWC would be the appropriate option for recovery of the carrying cost of prepayments. Staff says that response was provided on March 31, 2008, six weeks prior to Staff's rebuttal testimony filing on May 14, 2008. Staff's final position on the recovery of any carrying costs associated with prepayments is set forth in rebuttal testimony and does not recommend recovery of these derived costs through CWC.

Staff states that recovery of costs associated with collateral postings for gas purchase contracts could be considered a case of first impression. Staff indicates that the posting of collateral associated with energy purchases was considered in the recent electric power procurement cases. In those proceedings, Staff says the costs associated with collateral postings were specifically identified as costs to be recovered under Rider PER for AIU. Staff opines that for the sake of consistency, the costs of collateral postings for the gas utilities should be treated in the same manner as the costs of collateral postings for the electric utilities.

Staff does not claim that such costs will be recovered through the PGA mechanism, but rather offers the recovery of the costs associated with collateral postings through the PGA mechanism as an option to be considered by the Commission. Staff states that this proceeding is to set base rates, not to consider specific costs to be recovered through other rate mechanisms. According to Staff, any costs to be recovered through the PGA would be considered in the annual reconciliation dockets to specifically review the costs AIU proposes to recover through the PGA rates.

AIU witness Moloney states that the counterparties will likely continue to seek to be fully secured until ratings return to investment grade levels. Staff states that it

anticipates any rate increases determined in these proceedings would provide some level of comfort to the ratings groups who could raise the AIU credit ratings above investment grade levels. Staff adds that Standard & Poor's ("S&P") has already given AIU a positive outlook. Should AIU's credit ratings be upgraded and the counterparties no longer require to be fully secured, Staff says that ratepayers would be funding a cost that ceases to exist for the utilities, if AIU's proposal is approved. According to Staff, the option for the cost of collateral postings to be recovered through the PGA recovery mechanism, rather than through base rates, would provide some assurance that those costs would only be collected from ratepayers as they are incurred and not through the indefinite future. Staff recommends that the Commission disallow AIU's proposed pro forma adjustments to include as purchased gas expense an interest component related to cash collateral and prepayments for the gas utilities.

In its Reply Brief, Staff argues that collateral and prepayments are simply "opportunity" costs and not actual out-of-pocket costs incurred by AIU. Staff says AIU does not write a check to cover interest (carrying costs) related to prepayments. Staff also states that AIU's exposure will cease to exist when ratings return to investment grade levels. Staff complains that no provision is included in AIU's proposal should the ratings return to investment grade levels and exposure ceases to exist between rate case filings.

c. The AG's Position

AIU has included interest related to posting cash collateral and prepaying for gas purchases in pro forma test year gas O&M expenses calculated by taking the average balances of cash collateral and prepayments and applying the short-term rates by month to those average balances. The AG proposes two modifications to AIU's interest calculations. First, the AG says AIU's interest payments should be based upon the full 12 months of data available subsequent to the time debt ratings were downgraded. Second, in calculating the pro forma interest expense, the AG recommends that the latest known applicable interest rate be used rather than the month-by-month interest rates. The AG indicates that the effect of these adjustments is to decrease AmerenCILCO's gas expenses by $233,000, AmerenCIPS' gas expenses by $31,000, and AmerenIP's gas expenses by $391,000. AIU accepts the AG's adjustment.

d. Commission Conclusion

Having reviewed the parties' positions, the Commission finds Staff's arguments to be somewhat confusing and contradictory. In fact, it is not entirely clear what Staff recommends, although it seems to suggest that AIU should not be allowed to recover the costs of collateral and prepayments from ratepayers. The Commission first notes that while AIU may not write checks for collateral or prepayments, it does not write checks for depreciation expense or cost of capital. Those costs are reflected in base rates. Additionally, while there is no provision to change rates should AIU's credit ratings improve between rate cases, there is no provision to change any component of base rates if circumstances change between rate cases. In short, to the extent Staff

argues that AIU should not be allowed to recover the cost of collateral or prepayments from ratepayers through base rates, that proposition is rejected. These appear to be prudent, reasonable costs incurred by AIU during the test year and it is appropriate for AIU to pass the costs on to ratepayers through base rates. The Commission finds the AG's recommended approach for calculating the annual interest cost associated with collateral and prepayments, to which AIU has agreed, to be reasonable for purposes of establishing rates in this proceeding, and it is hereby approved.

8. Reliability Initiatives

a. AIU's position

AIU seeks recovery of costs for reliability initiatives that consist of, among other things, projects for tap fusing, device inspection, lightning arresters, circuit inspection, multiple device interruption, improving worst performing circuits, underground cable replacements, and distribution service replacements. AIU claims that all of these projects are benefiting or will benefit customers.

Staff witness Ebrey and AG/CUB witness Effron propose to disallow AIU's costs related to reliability initiatives. Ms. Ebrey claims that the Commission does not accept budgeted amounts for evidence supporting approved rate case expense and that such costs are not known and measurable. Similarly, Mr. Effron argues that there is little evidence that the actual reliability expenditures are increasing at anything like the rate being forecasted by AIU. In AIU's view, none of the reasons proffered by Ms. Ebrey and Mr. Effron provide a basis to disallow AIU's costs for reliability initiatives.

AIU argues that Ms. Ebrey is wrong that the Commission does not accept budgeted amounts for evidence supporting approved rate case expense. According to AIU, Ms. Ebrey characterizes AIU witness Getz’s examples of past instances where the Commission has approved budgeted or estimated expenses as deficient without attempting to explain how. AIU contends that Ms. Ebrey completely fails to address the examples provided by Mr. Getz. Mr. Getz states that in the most recent AIU gas rate cases, rate case expense for all three utilities was based on estimates. AIU further asserts that in the prior electric rate cases, at least five adjustments were proposed based on budgets or estimates. According to AIU, these were: weather normalization adjustments, wage and salary adjustments to labor expense, pensions and benefits, tree trimming, rate case expense, and AmerenIP acquisition cost savings. AIU claims all five adjustments were contested by at least one party in the proceedings, and three of the five ultimately were set based on budgets or estimates.

In the last electric rate cases, AIU explains that for labor expense, incentive compensation was excluded while wage and salary expenses included 2006 budgeted percent increases. AIU says pension and benefits were based on 2007 actual expense. According to AIU, the Commission approved the 2006 budget amount for AmerenIP tree trimming costs and the Commission approved a combination of actual and estimated

amounts for rate case expense. Finally, AIU says AmerenIP acquisition savings as budgeted through 2006 were included in the final determination of revenue requirement.

AIU contends that Ms. Ebrey also is mistaken in her belief that, because projects are currently "being identified and will be engineered and scheduled," that the costs can not be known and measurable. AIU argues that to the contrary, the broad scope of work to be performed has been identified and included in the pro forma adjustment. AIU claims calculations were made based on the type of work, the labor rates, materials, and equipment involved for the costs in the aggregate. AIU insists that the fact that some engineering and scheduling on these projects is ongoing does not mean that the projects are not expected to be completed. According to AIU, engineering often continues even after a project has started. In AIU's view, the costs are known and measurable.

AIU argues that Mr. Effron likewise fails to support his claim that there is little evidence that the actual reliability expenditures are increasing at anything like the rate being forecasted by AIU. AIU contends that increases in reliability expenditures are reasonably certain to occur, and, in fact, are occurring. AIU also believes the increases are determinable. AIU says reliability costs have grown from $816,000 in the 2006 test year to $2.2 million in 2007. According to AIU, the 2007 expenditures constitute a 265% increase from the test year expenses. AIU claims that it has already spent approximately $1.5 million related to reliability projects through March 31, 2008. AIU claims these expenditures are on track with budgeted amounts.

In AIU's view, Mr. Effron's claim that there is little or nothing in AIU's actual experience to support the level of reliability spending forecasted by AIU for 2008 is equally unavailing. AIU insists the 2008 expenditures are known, measurable, and on track with budgeted amounts. AIU argues that under the circumstances, past experience is not indicative of current and future levels of reliability expenditures. The Commission has placed increasing emphasis on reliability, and in response AIU claims to have raised the level of reliability spending. AIU asserts that unique coding has been implemented in the past few years to enhance tracking of specific reliability initiatives.

In its Reply Brief, AIU argues that although there may be some flexibility or shifting between items in the reliability plans, it is expected that AIU will still spend the budgeted amounts. In addition, AIU dismisses the AG's contention that there is no evidence that AIU is actually experiencing increased spending of this magnitude on electric reliability programs. AIU claims it has provided evidence that increases in reliability expenditures are reasonably certain to occur, and, in fact, are occurring.

b. Staff's Position

Staff recommends disallowing AIU's proposed pro forma adjustments for reliability initiatives because they are based on a 2008 budget and, in Staff's view, are not known and measurable. AIU argues that its budgets are known and measurable; however, Staff insists that the evidence provided in this case does not support that

argument. Staff states that while the Commission may approve budgeted amounts in a rate case final order; those amounts have been analyzed by the parties to determine their reasonableness and are not approved simply because they have been budgeted. Staff asserts that there are wide variations between the amounts AIU budgeted for reliability projects in 2007 and the actual costs incurred. Staff claims there is a significant difference between the number of projects planned, or budgeted, as of July 17, 2007 and as of December 31, 2007.

Staff also says there have been multiple changes for each AIU division during a two-month period. Staff cites Section 287.40 of Part 287, which states in relevant part:

> These adjustments shall reflect changes affecting the ratepayers in plant investment, operating revenues, expenses, and cost of capital 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.

According to Staff there is uncertainty associated with AIU's reliability projects; thus, AIU's pro forma adjustments should be disallowed.

In its Reply Brief, Staff asserts that AIU incorrectly claims Staff proposes to disallow costs associated with reliability initiatives. Staff says its proposal is to disallow the pro forma adjustment based on the increase of the 2008 budget over 2006 actual costs. According to AIU, the actual 2006 level of costs for reliability initiatives has not been proposed for disallowance by Staff. Staff says AIU claims that Ms. Ebrey does not explain how Mr. Getz's examples of approval of budgeted amounts in rate cases fall short. Staff claims, however, that Mr. Getz provided that explanation during cross-examination. (Staff Initial Brief at 175, citing Tr. at 576)

c. The AG's Position

According to the testimony of Mr. Stafford, AIU is experiencing increases in electric operating expenses to undertake and expand their reliability programs. To recognize the effect of these increases, AIU is proposing pro forma adjustments to increase the electric reliability expenditures from the amounts actually incurred in the 2006 test year to the forecasted expenditures in 2008 which increase AmerenCILCO's electric expenses by $2,526,000, AmerenCIPS' electric expenses by $1,763,000, and AmerenIP's electric expenses by $13,613,000.

In the AG's view, the problem is there is no evidence that AIU is actually experiencing increased spending of this magnitude on electric reliability programs. The AG claims AIU's actual spending on reliability programs in 2007 - the year immediately after the test year in these cases – was not materially different from what it was in the proposed test year. Mr. Getz cites the increases in reliability expenditures that have already taken place from the 2006 test year to 2007 and the first quarter of 2008, stating

that spending on reliability projects increased from $816,000 in 2006 to $2.2 million in 2007 (representing all three electric utilities combined).

The AG believes that the percentage increase from 2006 to 2007 is not particularly meaningful because of the relatively low base off which the increase is calculated. Even assuming that the spending continues to grow at that rate, the AG states that the total for the three companies would be approximately $5.8 million in 2008, which would still fall well short of AIU's forecast of $18.7 million. Of the three companies, the AG claims only AmerenIP saw a significant increase in reliability spending from 2006 to 2007. Even if the spending in 2008 continues at the same rate as in the first quarter, the AG says spending for the full year would be $6 million, which would still be well short of AIU's forecast of $18.7 million.

In its Reply Brief, the AG says AIU mischaracterizes the AG's position when it states that AG/CUB witness Effron proposes to disallow all of AIU's costs related to reliability initiatives. The AG says Mr. Effron recommends only that the pro forma adjustments made for reliability initiatives through 2008 be disallowed. To the extent that actual spending in 2007 has increased beyond the 2006 test year levels, the AG includes those increases in its proposed adjustments. The AG recommends that the Commission reject those pro forma increases which it says are inconsistent with actual AIU experience. Even using the first quarter expenditures from 2008 as a guide, the AG claims AIU's total for the year would be only $7.2 million.

d. Commission Conclusion

Staff has proposed adjustments to disallow AIU's proposed pro forma adjustments for reliability initiatives since they are based on a 2008 budget and, in Staff's view, are not known and measurable. AIU argues that its budgets are known and measurable; however, Staff insists that the evidence provided in this case does not support that argument. Like Staff, the AG recommends that AIU's proposed pro forma adjustments for reliability initiatives be disallowed in their entirety. The AG argues that because neither the trend in actual reliability spending nor the actual spending rate in 2008 through the first quarter supports AIU's forecasts, there is little evidence that the actual reliability expenditures are increasing at anything like the rate being forecasted by AIU. Both Staff and the AG complain that AIU suggests they propose disallowing all costs associated with reliability initiatives when, in reality, they recommend disallowing AIU's proposed pro forma adjustment that would increase the test year level of these costs.

As an initial matter, it appears that AIU has, either intentionally or inadvertently, mischaracterized the Staff and AG proposals. Contrary to AIU's claim, Staff and the AG do not propose disallowing all costs associated with reliability initiatives; instead, they propose disallowing AIU's proposed pro forma adjustment to the test year level of reliability initiatives. Thus, the only question before the Commission is whether AIU's proposed pro forma adjustment should be reflected in operating expenses for the test year.

The Commission next notes that in her rebuttal testimony, Ms. Ebrey suggests that the vast majority of AIU's proposed pro forma adjustment for reliability initiatives is for pole replacements. The following table derived from Ms. Ebrey's direct and rebuttal testimony shows that her assertion appears to be correct:

Company	Proposed Test Year Reliability Initiatives	2008 Pole Replacements Budgeted
AmerenCILCO	$2,700,429	$2,545,592
AmerenCIPS	2,035,118	1,567,040
AmerenIP	13,982,361	12,151,845
Total	$18,717,908	$16,264,477

AIU has not explained why it is appropriate for pole replacements to be treated as an operating expense through so called reliability initiatives. In the Commission's view, pole replacements, as a general proposition, are capital expenditures for long lived assets which should be included in rate base. The table in Ms. Ebrey's rebuttal testimony indicates that between 2006 and 2008, AIU proposes to increase pole replacements treated as operating expenses from less than $300,000 actually incurred in 2006 (Staff Ex. 13.0 at 35) to over $16,000,000 proposed for 2008. The record of this proceeding does not support AIU's proposal to make proposed pro forma adjustments to electric operating expenses related to reliability initiatives. The Commission rejects AIU's proposed pro forma adjustments in their entirety.

9. Public Utility Fund Base Maintenance Contribution

a. AIU's Position

Section 2-203 of the Act requires certain electric utilities in Illinois to “contribute” their pro rata share of $5.5 million to the Public Utility Fund. AmerenCILCO, AmerenCIPS, and AmerenIP included expenses for the Public Utility Fund base maintenance contribution (“PUF BMC”) in test year revenue requirements. The total test year revenue requirement for this item for the three utilities is about $1.6 million.

Section 2-203 expires by its terms on January 1, 2009. AIU indicates that at the time a bill (Senate Bill ("SB") 1926, as amended by Senate Amendment 1) was pending in the General Assembly that would retain PUF BMC contributions until January 1, 2014. AIU says that despite the fact that PUF BMC contributions may be extended, Staff witness Ebrey proposes an adjustment to exclude expenses related to the PUF BMC from test year revenue requirements.

AIU believes Ms. Ebrey's adjustment to exclude PUF BMC expense is improper for at least two reasons. According to AIU, the adjustment violates the Commission's test year and pro forma adjustment rules. AIU says Section 287.40 of Part 287 provides for pro forma adjustments to historical test year data that are reasonably certain to occur within 12 months after the filing date of tariffs. AIU indicates that tariffs in this proceeding were filed on November 2, 2007 and argues that pro forma adjustments may extend to November 2, 2008. According to AIU, Staff's proposed adjustment relates to an expense item that will not be affected, if ever, until January 1, 2009. The adjustment, AIU contends, is outside the pro forma adjustment period and improper for that reason alone.

AIU also avers that Staff's adjustment is prohibited single-issue ratemaking. AIU argues that there are many different costs that could increase or decrease beyond the test year. AIU says that is the point of limiting the period for pro forma adjustments; to ascertain known and measurable adjustments to test year income and expense. According to AIU, Ms. Ebrey did not undertake a review to determine whether there was any legislation that would potentially increase AIU's costs after January 1, 2009. By recommending exclusion of a single expense item beyond the pro forma adjustment period, AIU asserts that Staff, in addition to violating test year rules, also inappropriately engages in single-issue ratemaking.

AIU says it recognizes the possibility that it may not incur PUF BMC expenses after January 1, 2009. In AIU's view, Staff's adjustment, however, fails to recognize that it is just as likely, if not more likely, that PUF BMC charges will not only be extended, but may be increased above the amounts required by current law. AIU says that in contrast to the one-sided nature of Ms. Ebrey's treatment of PUF BMC charges, it proposes a resolution that it believes is fair to both the companies and ratepayers. Specifically, AIU proposes that rates be set initially based on the level of PUF BMC expense included in Ameren Ex. 43.5. AIU suggests the Commission could authorize an across-the-board change to tariff rates effective January 1, 2009, to reflect PUF BMC funding requirements. If no contributions are required after January 1, 2009, the cost to ratepayers will be $0, AIU claims. AIU says that if contributions are required, those costs can be properly recovered in rates, dollar for dollar, based on whatever funding level is approved by the legislature. AIU says it would recover their actual PUF BMC contribution expense, no more and no less.

b. Staff's Position

Staff proposed an adjustment to reduce operating expenses for the PUF BMC, which was authorized by Section 2-203 of the Act, but expires on December 31, 2008. Staff states that if SB 1926, as amended by Senate Amendment 1, becomes a Public Act, the PUF BMC would be extended until January 1, 2014, and Staff's proposed adjustment would not be necessary. According to Staff, while AIU offers a number of criticisms of Staff's adjustment, none of those criticisms change the fact that Section 2-203 of the Act will be repealed absent further legislation. Staff asserts that its proposal

provides the Commission an option depending on whether or not the legislature takes further action.

AIU points out that the amount of Staff's proposed adjustment does not consider that a portion of the total amount charged to Account 928 is not assigned to electric distribution operations. Staff agrees with this correction and reflects the adjusted amount in its proposed electric revenue requirements attached to its Initial Brief.

In response to AIU's arguments regarding pro forma adjustments, Staff contends that Section 287.40 addresses only pro forma adjustments that may be proposed by a utility company. Staff claims that Section 287.40 was never intended to limit Staff's ability to propose adjustments. Staff says that AIU's proposal would require ratepayers to pay for a soon to be non-existent PUF BMC, and if collected, AIU would have no obligation to remit the PUF BMC to the Illinois Department of Revenue. According to Staff, AIU wants the Commission to believe that the recovery of an expired cost accomplishes the requirement that all rates or other charges be just and reasonable as required by Section 9-101 of the Act.

Staff also disagrees with AIU that Staff's proposed adjustment to remove the PUF BMC is prohibited single-issue ratemaking. Staff states that single-issue ratemaking would occur if the Commission would, in a separate and presumably subsequent proceeding, consider or revise a single revenue or expense item. (Staff Reply Brief at 84, citing Business and Professional People for the Public Interest v. Illinois Commerce Commission, 146 Ill. 2d. 175, 244, 585 N.E.2d 1032) ("BPI II") In the instant proceedings, Staff indicates that AIU is seeking a general increase in rates under Section 9-201 of the Act. Staff says a general increase in rates is intended to consider all components of the ratemaking formula (i.e., revenues, expenses, rate base and rate of return). Therefore, Staff does not believe AIU's single-issue ratemaking argument is applicable.

c. Commission Conclusion

Based upon its review of the record and the parties' arguments, the Commission rejects Staff's proposal to reduce operating expenses associated with the PUF BMC. The Commission concludes that this possible change in the statute is not known with a sufficient level of certainty to incorporate the potential impact in this proceeding. Additionally, the Commission is concerned that the actual change, if it were to happen at all, would not take affect until January 1, 2009. As for AIU's alternative proposal, because it has rejected Staff's proposed disallowance, it seems moot. The Commission is also concerned that were it adopted, this proposal might be considered single-issue ratemaking.

10. Depreciation Life for Electric Distribution Equipment

a. AIU's Position

AIU presents the testimony of and a depreciation study prepared by Mr. Wiedmayer of Gannett Fleming. AIU asserts that the service life of utility property can be defined as the period of time from its installation until it is retired from service. According to AIU, the currently approved service life estimates were determined in conjunction with utility-specific service life studies that were performed by three depreciation experts at different firms for each electric utility. Mr. Wiedmayer proposes estimates based on his informed engineering judgment after an analysis of available historical service-life data related to the property, a review of management's current plans and policies, a review of the prior approved service-life estimates, and a review of service lives estimated by other electric companies. AIU submits that both the approved lives and proposed lives were reached using industry-standard methodologies, and while these studies revealed a wide range of estimated service lives, AIU suggests there is nothing unusual about this.

AIU complains that Staff's recommendation proposes no specific adjustment, but suggests that the depreciable lives for certain distribution plant accounts such as meters should be the same for all three utilities. Staff witness Rockrohr premises his recommendation on the observation that AIU is now operating under common management and, therefore, equipment is to be constructed and maintained to the same or nearly the same standards among all three utilities. AIU avers that Mr. Rockrohr reasons that the same equipment would remain in service the same number of years for each of AmerenCILCO, AmerenCIPS, and AmerenIP, and therefore should be assigned the same service life.

AIU states that absent common management, different depreciable lives were appropriate, and that it was reasonable for CILCO, CIPS, and IP to have different depreciable lives for distribution plant when the utilities were not affiliated. AIU submits that the mere fact of common management does not justify use of a single depreciable life for distribution plant.

AIU argues that management practice is just one factor to be used in determining depreciable lives, not the only or dispositive one. AIU claims that Mr. Wiedmayer's study showed other factors justified a wider range of estimated service life. According to AIU, his study determined that over 500 different models (or variations) of meters are in service on the AIU system, many of which were manufactured by a number of different companies, installed at different times, and subject to different conditions of service. AIU posits that Staff's recommendation is not based on a particularized study but is instead based on the fact that consolidation has taken place.

While Mr. Wiedmayer testified that he would expect the depreciable lives for certain plant accounts to be more similar in the future, he does not believe that a single depreciable life is warranted at this time. AIU notes that the utilities have only been

affiliated since 2005, and submits that this is too short a period to have a material effect on the service lives of utility plant.

b. Staff's Position

Mr. Rockrohr recommends that AIU utilize a common depreciable life for electric distribution equipment if that equipment is used at all three utilities in an identical or nearly identical manner. Mr. Rockrohr acknowledges that the average age of equipment in the field at the three utilities is not identical. He explains, however, that looking forward, the service life of equipment at each utility will depend more upon the inspection and maintenance practices now in place than on the existing age of the equipment that is in the field. Mr. Rockrohr maintains that AIU should select a common depreciable life for equipment categories in which the equipment is utilized in an identical or nearly identical manner.

c. CUB's Position

CUB opposes AIU's recommendation to assign different service lives to distribution equipment that is used in an identical fashion in each utility's service areas in central and southern Illinois. CUB notes that Mr. Wiedmayer explains that the Commission approved the present depreciation rates for AmerenCILCO in 1994, for AmerenCIPS in 1992, and for AmerenIP in 1992. The depreciable lives of various categories of distribution equipment were set at those times. In those years, CILCO, CIPS, and IP were not affiliated with one another, and distribution facilities were not necessarily utilized and maintained in the same manner at each of the utilities. CUB notes that while it may have been reasonable that the same or similar equipment was assigned a different depreciable life at each utility in the past, the situation has changed. CUB submits that AIU now uses the same or nearly the same electric distribution construction and maintenance standards at each utility, and if the same equipment is to be installed and maintained in an identical manner at each utility then it is logical that the same equipment should, on average, remain in service the same number of years.

CUB argues that in order to maintain consistency of the calculation of the depreciable lives between similarly maintained equipment, the Commission should adopt Mr. Rockrohr's recommendation to amend AIU's depreciation schedules in a manner that provides the same depreciable lives for categories of distribution equipment that is installed and maintained in an identical fashion at each utility.

d. Commission Conclusion

The Commission notes that prior to the utilities' affiliation, different depreciable lives were determined as appropriate for each utility. The service life estimates were determined in conjunction with utility-specific service life studies that were performed by depreciation experts for each electric utility. These studies were based on available historical service-life data related to the property, a review of management's current plans and policies, a review of the prior approved service-life estimates, and a review of

service lives estimated by other electric companies. The Commission believes that establishing single service lives for certain types of electric distribution utility property may be appropriate in the future but is not practical at this time.

Among other things, Staff and CUB fail to take note that many different depreciation lives were determined at different times and subject to different conditions of service at the time of installation. Thus, the Commission believes that the current approved service life estimates that have been assigned to plant property should remain. However, AIU is instructed in future rate cases to consider the possibility of assigning common service lives for plant accounts if they are utilized in the same manner at each utility in order to maintain consistency in the calculation of the depreciable lives among similarly maintained equipment.

11. Net Salvage Method for Depreciation Expense

a. AIU's Position

AIU notes that the general aim of depreciation accounting is to distribute the cost of fixed capital assets, less net salvage, over the estimated useful life of the assets in a systematic and rational manner. AIU witness Wiedmayer proposes using the traditional, accrual method for accounting for net salvage, by allocating the cost to each year of the assets' service life rather than when the actual salvage-related costs are incurred. AIU points out that this is the approach used by the Commission for many years and by the majority of commissions in other jurisdictions. AIU submits that the fundamental goal of depreciation accounting is to allocate the full cost of an asset, including its net salvage cost, over its economic or service life so that utility customers will be charged for the cost of the asset in proportion to the benefit they receive from its consumption.

AIU argues that IIEC witness Selecky's proposed net salvage approach is a departure from Commission precedent, and is inconsistent with the approach used by the vast majority of state commissions. In light of this fact, AIU argues that one would expect Mr. Selecky to have compelling reasons before asking the Commission to alter its traditional practice. According to AIU, he presents none, however, and a number of other considerations counsel against adopting his approach.

First, AIU argues IIEC's proposed net salvage approach is inconsistent with the USOA. AIU notes that the USOA requires utilities keep their accounts on the accrual basis. AIU points out that utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property. AIU submits that to only recognize salvage-related costs at the time any salvage-related dollars change hands would be to follow the "cash" basis of accounting, contrary to the instructions of the USOA.

According to AIU, Mr. Selecky's approach also violates the ratemaking principle of customer equity. AIU argues the principle of equity demands that the customers who enjoy a given benefit should pay their portion of the related costs, no more, no less.

AIU submits that while its approach would allocate net salvage costs associated with given assets to the customers being served by those assets, IIEC's approach would mismatch those who benefit from the net salvage costs with those who pay such costs.

AIU posits that IIEC's proposal would also recover the entire element of an asset's cost of service from customers that either received no benefit from the asset or only a portion of the asset's service value. AIU argues this is a violation of the principle of equity, and no different than requiring one generation of customers to pay the entire original cost of an asset that served many generations.

b. IIEC's Position

IIEC proposes an adjustment to depreciation rates because of what it views as the inequity of using net salvage cost calculations based on historical data. IIEC also objects to what it calls the inclusion of unproven, inappropriate inflation costs in depreciation rates. IIEC also argues that if the calculation of depreciation rates is not changed, it will fail to recognize the time value of money.

According to IIEC, AIU's depreciation expense should reflect the actual net salvage costs caused by ongoing transmission, distribution and general plant retirement, similar to the treatment afforded other expenses. IIEC argues the Commission should not approve AIU's proposed net salvage ratios, which it claims incorporate estimated inflation and ignore the purchasing power of the dollar. According to IIEC, AIU's estimates of net salvage are based on judgment, considering factors that are not well-defined and historical net salvage data that AIU admits were in some instances unreliable and limited. IIEC claims these deficiencies in the historical data led Mr. Wiedmayer to rely on net salvage estimates from other electric utilities. IIEC notes that the net salvage percentages that AIU proposes to incorporate in its depreciation rates are not exclusively based on AIU's own data, and IIEC argues that those percentages do not reflect AIU's actual experience.

IIEC contends that there is no dispute that inflation, which is at the core of IIEC's challenge to AIU's calculated depreciation rates, is a component of the net salvage estimates AIU has built into its proposed depreciation rates. IIEC says Mr. Wiedmayer used historical net salvage data to develop net salvage percentages by dividing the net salvage cost associated with retiring an asset by the original cost of the asset. IIEC insists that because the calculation uses nominal dollar amounts, net salvage cost is expressed in current dollars and the original cost of the asset is stated in the dollars for the year the asset was originally placed in service, inflation over the period between the two events is captured in the calculation. IIEC notes that the pre-inflation, nominal dollar figures associated with past investments are divided into the post-inflation, real dollar amounts for the cost of salvage. This calculation, IIEC argues, incorporates an unproven assumption that future inflation will occur at the same rate as past inflation, resulting in different ratios than actual experience would indicate. IIEC says the net salvage percentage is then incorporated in a depreciation rate that is applied uniformly over the useful life of the assets in the relevant account. According to IIEC, application

of the single rate means that customers today will pay the same number of dollars as customers 30 to 40 years in the future, notwithstanding the difference in real purchasing values of those nominal dollars. IIEC contends that customers today will pay the same number of dollars as future customers despite the fact that current salvage expenses are much lower than the amounts collected from current customers and that without accounting for implicit inflation at a historical rate, which is inherent in the calculation. IIEC contends that the effect of these methodological flaws is an excessive level of depreciation expense.

IIEC argues that another adverse effect of the methodological flaws is unfairness in AIU's rates, and that the flawed calculations will foster significant inter-generational inequities. IIEC submits that under AIU's proposal, AIU customers will pay costs today that the utility may not incur for another 40 years. Moreover, IIEC argues in terms of real dollars, the uniform nominal amount that AIU would charge customers over the decades of assets' lives would actually require significantly less of future ratepayers.

c. The Commercial Group's Position

The Commercial Group agrees with Mr. Selecky that AIU has inflated depreciation expense by over-projecting net salvage expense, and that AIU proposes net salvage expense that is 2 to 5 times greater than AIU's current net salvage expense. The Commercial Group submits that AIU does so by projecting future inflation rates into salvage expense calculations. The Commercial Group avers that guessing and projecting the inflation rate for the next 30, 40, or 50 years into salvage expense is not likely to produce a result that follows actual salvage cost. The Commercial Group suggests this is demonstrated by the fact that actual current salvage expense is many times lower than the proposed salvage expense rate recovery. What this means, according to the Commercial Group, is that ratepayers in 2009 would pay the same actual dollar amount for the salvage expense of a set of electric poles to be replaced in 2040 as would a ratepayer in 2039; and considering the effect of inflation, means that the 2039 ratepayer would pay significantly less in real dollars for salvage of those poles in 2040 than would the ratepayer in 2009.

The Commercial Group submits that this represents a substantial intergenerational shift in depreciation expense that unfairly harms current ratepayers. Accordingly, the Commercial Group urges the Commission to adopt the lower depreciation rates as recommended by Mr. Selecky.

d. Commission Conclusion

The Commission does not concur with IIEC and the Commercial Group's proposal to depart from the Commission's current treatment of net salvage costs; specifically, using the traditional, accrual method of accounting for net salvage. Although there are some regulatory commissions that have moved away from the methods prescribed for depreciation, this Commission is not inclined to do so as the evidence does not show it is necessary. It has been appropriate to use the traditional

method by allocating the cost to each year of the assets' service life rather than when the actual salvage-related costs are incurred. This method of depreciation allocates in a systematic and rational manner the service value of depreciable property over the service life of the property. IIEC's complaint that customers today will pay the same number of dollars as future customers represents a misunderstanding or misrepresentation of the purpose of systematic recovery of depreciation expense, which provides for rate recovery of long-lived assets over their expected useful life. In contrast, the net salvage approach advocated by IIEC and the Commercial Group would improperly push costs into the future that are more appropriately borne by current ratepayers. The Commission understands why such an approach may appear attractive in the short-run, but in the long-term it provides no benefit to ratepayers in aggregate. Further, contrary to the Commercial Group's assertion, the Commission concludes that AIU's reliance on some net salvage estimates from other electric utilities does not result in over-projecting net salvage expense relative to AIU's current net salvage expense. In conclusion, the accrual method for calculating net salvage is consistent with the Commission accounting practices for regulated utilities, has been accepted, deemed appropriate for years, and the Commission remains convinced that it is appropriate in this case.

12. NESC Violation Correction Costs After the Test Year

a. AIU's Position

AIU agrees to track costs associated with correcting NESC violations as Staff proposes, however, AIU opposes disallowance of those costs. AIU states that the Commission and Staff imposed a number of programs, initiatives, and other requirements of Ameren during the various acquisition dockets. In 2003, in Docket No. 02-0428, the Commission approved Ameren's acquisition of CILCORP, which included its operating utility subsidiary, CILCO. In 2004, in Docket No. 04-0294, the Commission approved Ameren's acquisition of IP. In 2005, AmerenUE transferred its service territory in Illinois to AmerenCIPS. AIU claims that assuming responsibility for unknown past violations of the NESC were not made part of the conditions of approval. According to AIU, it has fulfilled all of its responsibilities required in the Commission's acquisition dockets and it would be unfair and inequitable to impose, at this time, additional conditions of acquisition by holding AIU responsible for costs due to improper initial construction occurring prior to Ameren ownership.

AIU contends that a significant portion of the violations of the NESC were due to improper initial construction which occurred prior to Ameren ownership. According to AIU, it has made certain commitments in response to the NESC issues, including, an agreement to track all costs associated with NESC compliance, an agreement to forego current recovery of test year expenses that it has incurred for NESC compliance, an agreement to forego future recovery related to the replacement of otherwise grandfathered single cross-arms at railroad or interstate highway crossings, and an agreement to forego future recovery for the replacement of down guys or overhead guys that were improperly constructed after Ameren ownership.

AIU submits that it has put forth a fair and responsible proposal under which its shareholders will bear the costs associated with violations occurring after Ameren assumed ownership of AmerenCILCO and AmerenIP. AIU argues that disallowing all costs associated with correcting NESC violations due to improper initial construction by a previous owner should be rejected for various reasons. AIU avers that the proposed disallowance fails to find AIU's prospective investments are imprudent, and further posits that the proposed disallowance is at odds with the goals and objectives of the Act. AIU further submits that Staff witness Rockrohr's recommendation runs afoul of the Commission's long held policy of encouraging the acquisition of financially troubled utilities.

AIU argues that in determining whether future replacement costs should be recovered, the Commission's attention should focus on the decision of AIU management to make the prospective replacements and not on past construction efforts, and submits it would be improper to look at the conduct of previous owners. Moreover, AIU argues it does not seek recovery for NESC compliance measures in this proceeding. AIU notes that it has agreed to withdraw its request for recovery for those replacements proposed as test year costs. AIU avers that it is premature to conduct a prudency examination of its post-test year NESC compliance efforts, and therefore, Mr. Rockrohr's disallowance should be rejected as it is unripe. AIU also states that Mr. Rockrohr has failed to consider the prudency of making NESC required replacements.

AIU points out that Mr. Rockrohr's position is that the utility should bear all the consequence of all improperly constructed facilities, without regard for who constructed the facilities or the adverse financial impact on AIU. While Mr. Rockrohr believes it would be unfair for customers to bear any consequence of the improper initial construction, AIU submits that there is no evidence that he contemplated the impact of his recommendation on AIU's financial health. AIU contends that while Staff believes that AIU could have made itself aware of pre-existing NESC violations by inspecting "some" of the distribution circuits, AIU submits that the facts suggest otherwise. AIU notes that the AmerenCILCO, AmerenCIPS, and AmerenIP service territories cover approximately 40,000 square miles and contain over 45,000 miles of distribution circuits supported by over 1,000,000 distribution poles. AIU submits that it is pure conjecture that spot checks would have uncovered the NESC violations at issue here.

AIU argues that it exercised due diligence and proceeded with its acquisitions based on the relevant information that was available at the time, and notes that the Commission approved each of the acquisitions with no findings of any shortcomings in Ameren's due diligence undertakings. AIU does not agree with Staff's assertion that in the event a utility system is not compliant with the NESC, corrective action must be taken pursuant to Commission Rule, 83 Ill. Adm. Code 305, "Construction of Electric Power and Communication Lines" ("Part 305"). AIU submits that Part 305 of the Commission's Rules is not as inflexible as Staff suggests. AIU notes that Section 305.130 provides for exemptions from NESC standards, and avers that the Commission

can provide waivers of NESC standards or even modify the standards if the Commission so chooses.

b. Staff's Position

Staff recommends that AIU's costs associated with correcting certain NESC violations that exist due to improper initial construction should be disallowed from rate recovery. Mr. Rockrohr expresses concern that AIU intends to charge customers for re-constructing distribution facilities that CILCO, CIPS, and IP initially constructed improperly, and in the process earn a return on the costs associated with correcting the NESC violations. He further notes that as AIU's budgeting system does not separately track dollars associated with correcting NESC violations, he recommends that the Commission require that AIU track costs for correcting all NESC violations, and separately account for such costs. He also recommends that the Commission order that costs to correct violations that AIU itself caused not be approved for inclusion in rate base.

Staff argues that the alleged pre-existence of the violations prior to Ameren's ownership of the utilities is not a valid reason to pass these costs on to ratepayers. Staff submits that Ameren was not coerced or forced into purchasing CILCO and IP, and could have made itself aware of pre-existing NESC violations simply by inspecting some of the existing distribution circuits. Staff avers that as the merger of CIPS and UE was the catalyst for the formation of Ameren as a holding company, NESC violations within the operating area of CIPS can not be considered the fault of a prior owner. Mr. Rockrohr explains that based upon AIU's estimates, the compromise that AIU offers (whereby AIU would correct NESC violations consisting of single cross-arms at railroad and interstate highway crossings at shareholder expense) would equate to ratepayers paying for correcting about 95% of the NESC violations that are estimated to exist on AIU's system due to improper initial construction. Mr. Rockrohr posits that the compromise that AIU suggests is not reasonable, therefore he continues to recommend that the Commission order AIU to separately account for costs associated with correcting NESC violations that exist due to improper initial construction, and disallow those amounts from rates.

c. Commission Conclusion

As the Commission understands it, the previous owners of AmerenCILCO, AmerenCIPS, and AmerenIP constructed certain electric distribution facilities in a manner that are not in compliance with the NESC. Generally speaking, Staff objects to AIU passing along to ratepayers costs that are incurred to correct distribution facilities that were initially constructed in a manner that does not comply with the NESC. While it appears that AIU no longer requests to pass such costs on to ratepayers in this proceeding, AIU insists that it should not be responsible for the actions of the previous owners of AmerenCILCO, AmerenCIPS, and AmerenIP and should be allowed to recover from ratepayers the costs of remedying such NESC violations in the future.

Staff also recommends that the Commission order AIU to separately track and account for costs associated with correcting NESC violations that exist due to improper initial construction. AIU does not object to the recommendation. The Commission believes it is reasonable and it is hereby approved.

It appears that for purposes of establishing rates in this proceeding, there is no contested issue regarding proposed adjustments to rate base or operating expenses that flow from the reconstruction of electric distribution facilities that were improperly constructed in violation of the NESC. The Commission is, nevertheless, concerned about the position taken by AIU regarding this issue. The proposition that ratepayers should be responsible for paying the cost associated with improperly constructed electric distribution facilities as well as the cost of correcting the improperly constructed facilities is not one with which the Commission agrees. The suggestion that by disallowing from rates such costs constitutes an additional condition on any reorganization or merger is also rejected. In the reorganization or merger proceedings, AIU did not inform the Commission of the possibility that electric distribution facilities were not in compliance with the NESC and, as a result, the Commission did not consider the question or make any ruling on the matter.

Business decisions were made that resulted in CILCO, CIPS, and IP being owned by Ameren. The management and owners of Ameren, not ratepayers, made those decisions and they must live with the consequences. In this instance, the consequences will be that 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. While there is no rate base or operating expense impact in this proceeding, AIU is on notice that the Commission has no intention of passing such costs on to ratepayers in future rate cases. As for AIU's suggestion that Part 305 is flexible, the Commission simply reinforces that it expects AIU to comply with all applicable Commission rules, including Part 305.

13. Gas Account 880 – AmerenIP

a. AIU's Position

Staff proposes to adjust the test year expense for AmerenIP's gas Account 880 "Other expenses" because Staff believes the expense is high when compared to other time periods. Account 880 includes "the cost of distribution maps and records, distribution office expenses, and the cost of labor and materials used and expenses incurred in distribution systems operations not provided for elsewhere, including the expenses of operating street lighting systems and research, development, and demonstration expenses." (USOA for Gas Utilities Operating in Illinois) Staff proposes that a 3-year average (2005-2007) be used instead, reducing AmerenIP's Account 880 expense levels by $1,026,000. According to AIU, Staff does not challenge the prudency of the expenditures shown in AmerenIP's Account 880. Instead, AIU says Staff only argues that the expense appears to be somehow "excessive." AIU claims Staff's adjustment should be rejected for two reasons. First, Staff proposes an adjustment for

an account that appeared “high” but ignored countervailing adjustments for accounts that may have been lower in the test year than other years. Second, AIU claims to have shown that it is not reasonable to evaluate this account on an individual basis. AIU says account 880 is only one of a number of related transmission and distribution (“T&D”) O&M accounts where costs can shift and vary year to year based on the level of activity and required work.

According to AmerenIP, the majority of O&M activities performed on its T&D facilities is very similar, and are managed, supervised, and performed by essentially the same resources, which include AmerenIP employees and third-party contractors. AIU claims the shift or change in costs between these accounts occurs based on the specific level of O&M activities needed and performed for the T&D main facilities in a given year. AIU states, for example, exposed pipe remediation, leak surveys, leak repairs, right-of-way clearing, main relocations, corrosion control, and painting are types of O&M work performed on T&D mains that may vary based on inspection cycle, facility condition, problem severity and magnitude, or highway department needs. Based on the classification of main, either transmission or distribution, and the type of work, operations or maintenance, AIU says the appropriate account is charged. AIU argues that it would be expected that, depending on the specific O&M needs, costs would not remain static among accounts.

AIU indicates that Mr. Lounsberry discussed Account 880, which is a sub-set of the larger grouping of T&D O&M accounts. To obtain a more accurate representation, AIU suggests that Staff should review the O&M costs for the T&D system in aggregate. In AIU's view, this approach provides a more accurate assessment of the reasonableness of the O&M costs versus evaluating individual accounts. During the period of 2005-2007, which includes the test year, AIU says the aggregate costs for AmerenIP's 800 series accounts have been reasonably consistent, with a slight upward trend. According to AIU, AmerenIP's average over this period for all T&D O&M costs is approximately $59.93 million, and no year deviates from this average by more than 6%. AIU argues that because it is reasonable to expect overall O&M costs to increase each year, the overall level of T&D O&M costs show that, when viewed in the aggregate, there is no basis for a concerns that T&D O&M costs are excessive.

AIU contends that Staff’s logic could also be applied to individual accounts where 2006 represented the lowest level of expense for 2005-2007. AIU notes that Staff does not recommend increasing the amounts requested to any account that had the lowest expenditure in 2006 and higher expenses in 2005 and 2007. AIU claims that Accounts 878 "Meter and house regulator expenses" and 879 "Customer installation expenses" both have significantly less costs in 2006 than in either 2005 or 2007 and are below average for the 3 years. Using Mr. Lounsberry’s analogy, AmerenIP asserts that since both of these accounts are lower than the three-year average for 2006, using averages rather than actual costs would require an increase rather than a decrease.

In addressing Mr. Lounsberry’s concerns regarding cost levels in other T&D accounts, Accounts 856 "Mains expenses," 863 "Maintenance of mains," 874 "Mains

and services expenses," and 887 "Maintenance of mains," AIU asserts that costs shift between the accounts, so that the appropriate way to determine if the O&M costs are just and reasonable is to evaluate and understand the trend for the overall cost of operating and maintaining the T&D system. In rebuttal testimony, Mr. Lounsberry indicated he no longer had any concerns regarding AmerenIP's Accounts 856, 863, 874, and 887 requested O&M levels. According to AIU, Staff has accepted that individual T&D accounts may vary from year to year, but that this does not mean the expense in any one account is unreasonable.

AIU asserts that Account 880 is one of the accounts from 850 though 894 that capture O&M costs for the overall T&D system. AIU says Account 880 can vary from year to year resulting in cost fluctuations in individual accounts and should be considered as part of the aggregate. AIU believes these T&D O&M costs, including costs of Account 880, must be considered at the aggregate level, as opposed to the individual account level, to accurately evaluate the O&M costs for the T&D system.

b. Staff's Position

Mr. Lounsberry recommends a reduction of $1,026,000 to AmerenIP's requested test year amount for Account 880. He states that AmerenIP requested $9,505,000 for its Account 880, but that his review found that AmerenIP's test-year expense was higher than any other period reviewed for this account. Mr. Lounsberry's review was limited to the three-year period 2005-2007, because in 2005 IP was transitioning to AIU's accounting system. Therefore, Staff believes any expense data for IP prior to 2005 uses a different accounting system and will not necessarily correlate to the AIU accounting system.

AIU responds that it is not reasonable to evaluate this account on an individual basis. AIU witness Colyer states that Account 880 is only one of a number of related T&D O&M accounts where costs can shift and vary year to year based on the level of activity and requirement work. Instead, Mr. Colyer indicates that Account 880 should be considered as a variable part of the aggregate 800 series of O&M accounts for the T&D system. Mr. Colyer also notes that Mr. Lounsberry's proposal does not indicate AmerenIP's proposed Account 880 amount was unreasonable, but that the requested amount was just higher than other years.

Mr. Lounsberry does not agree with Mr. Colyer's assertion that the aggregation of about 40 different accounts will demonstrate the reasonableness of any individual account. However, in order to provide a complete review, Mr. Lounsberry conducted such an aggregation for comparative purposes only. Staff says this review indicates that when using the same 3-year period (2005-2007) that Mr. Lounsberry had used to normalize the individual Account 880 amount to review the aggregation of the 40 different 800 series accounts, his analysis came up with virtually the same result as looking at Account 880 individually. Specifically, Staff claims the 3-year average from aggregating the Account 800 series of T&D O&M amounts shows AmerenIP's test year request was about $940,000 above that average. According to Staff, the review of the

aggregate accounts also supports Mr. Lounsberry's original adjustment to reduce the Account 880 expense amount by $1,026,000.

c. Commission Conclusion

The Commission has reviewed the record and the parties' arguments regarding the proper costs to include in Account 880. As Staff's analyses demonstrate, AIU's arguments do not withstand scrutiny. Whether Account 880 is analyzed individually or with the other O&M accounts for T&D in aggregate, the test year amounts are abnormally high by approximately $1 million. As a result, the Commission finds Staff's proposal to reduce the amount of Account 880 costs that AmerenIP may pass along to ratepayers by $1,026,000 reasonable and it is hereby adopted.

14. Gas Accounts 830 and 834 - AmerenCILCO

a. AIU's Position

With regard to gas Accounts 830 "Maintenance supervision and engineering" and 834 "Maintenance of compressor station equipment" for AmerenCILCO, Staff proposes to adjust the expense levels in these accounts to reflect an average of the expenses over a 5 year period from 2003- 2007. According to AIU, no party has suggested that the expenses in these accounts were not prudently incurred; rather, Staff suggests that the test year levels of these expenses were excessive. AIU maintains that the reason for the variation of costs from year to year in Accounts 830 and 834 is that internal labor costs can shift between accounts from year to year as a result of the cyclical nature of maintenance activities, capital projects, and the type of activity being performed. AIU asserts that it is not appropriate to consider increases in costs recorded to Accounts 830 and 834 in isolation. Rather, AIU says accounts 830 and 834 must be considered in the context of the combined gas storage accounts.

According to AIU, Staff witness Lounsberry's logic could also be applied to AmerenCILCO gas storage accounts where 2006 represented the lowest level of expense in the 2005-2007 periods. AIU relates that Mr. Lounsberry does not recommend increasing the amounts requested for any accounts that had the lowest expense in 2006 and higher expenses in 2005 and 2007, such as Account 816 "Well expenses" where the expenses were $211,724, $141,028, and $179,197 respectively for 2005-2007. AIU complains that Mr. Lounsberry also does not explain why the variations in Accounts 830 and 834 were unusual or what, if anything, made the test year expense unreasonably high.

To properly capture these variations, AIU claims Mr. Lounsberry would need to average costs for all related accounts, not just the ones that were higher. According to AIU, overall expense for O&M for gas storage for AmerenCILCO is relatively stable over time. AIU claims the low expense level in 2007 was due to an unusual capital expenditure amount for 2007 that shifted resources from O&M to capital expenditures. In AIU's view, this shows that the variance over the years to accounts like Accounts 830

and 834 represents shifts of expenditures between accounts, but not an overall increase in O&M expense.

On rebuttal, Mr. Lounsberry argues that using the 2003-2007 period for AmerenCILCO's Accounts 830 and 834 shows the aggregate amounts for 2004 and 2005 are the highest of the period. AIU contends that the 2005–2007 data for the combined gas storage accounts is more current and therefore more representative of expected ongoing costs going forward, because it reflects cost increases and the impact of the mergers of AIU. AIU believes the use of the 2005-2007 time periods to compare aggregate gas storage account costs is reasonable. AIU argues that using Mr. Lounsberry's analysis, one could pick an individual account in the test year with a lower than average balance and determine that an increase is actually required rather than a decrease.

b. Staff's Position

Mr. Lounsberry recommends a reduction of $25,000 to AmerenCILCO's requested test year amount for Account 830. He explains that AmerenCILCO's test year expense was the second highest expense over the 5 historical years reviewed and that AmerenCILCO's expenses associated with this account varied significantly during the 5 historical years. He also recommends a reduction of $54,000 to AmerenCILCO's requested test year amount for Account 834. AmerenCILCO requested $89,000 as its Account 834 test year amount, which Staff notes was the highest expense over the five historical years reviewed and that expenses associated with this account varied significantly during the 5 historical years.

Mr. Lounsberry does not agree with AIU's assertion that the aggregation of the gas storage accounts demonstrates the reasonableness of any individual account. In order to provide a complete review, however, Mr. Lounsberry conducted such an aggregation for comparative purposes only. Instead of limiting that review to the 3-year period that AIU used, Mr. Lounsberry actually used the full 5 years' of historical information that he had relied upon in making his initial adjustment. According to Staff, the combined gas storage accounts revealed that the total expenses were as follows:

2003	$ 909,000
2004	$ 888,000
2005	$1,463,963
2006	$1,419,581
2007	$1,151,275

Staff states that the years 2005 and 2006 had the highest aggregate totals by a significant amount. Therefore, Staff concludes that the aggregate accounts supports Mr. Lounsberry's proposal to reduce AmerenCILCO's Account 830 test year expense amount by $25,000. Staff also believes the aggregate of the accounts supports Mr. Lounsberry's proposal to reduce the Account 834 expense amount by $54,000.

AIU argues that use of the 2005-2007 data for the combined storage accounts is more current and therefore more representative of the expected on-going costs because it reflects cost increases and the impact of the AIU mergers. AIU also asserts that the O&M expense for gas storage is relatively stable over time and that the variances over the years to an account like Account 830 represent shifts in expenditures between accounts, but not an overall increase in O&M expense.

Staff says it analyzed the individual Account 830 costs over the period from 2003-2007. Staff claims this analysis demonstrates that at least for Account 830, the 2005-2007 data is not representative of the expense amount that AmerenCILCO requested for the 2006 test year. According to Staff, the expenses over the 2003-2007 time period were as follows:

2003	$ 8,000
2004	$65,000
2005	$34,000
2006	$58,000
2007	$0
Average	$33,000

In Staff's view, AIU did not demonstrate why the proposed test year amount for Account 830, $58,000, would be just and reasonable.

Similarly, Staff believes the Account 834 costs information for the years 2005 - 2007 data is not representative of the expense amount that AmerenCILCO requested for the 2006 test year:

2003	$ 3,000
2004	$20,000
2005	$29,000
2006	$89,000
2007	$33,000
Average	$34,800

According to Staff, AIU fails to demonstrate why the use of the year 2006 amount for Account 834, $89,000, would produce just and reasonable rates.

c. Commission Conclusion

Having reviewed the record and the parties' arguments, the Commission finds Staff's proposed reductions to Accounts 830 and 834, of $25,000 and $54,000, respectively, to be appropriate. While AIU's argument that gas storage cost accounts should be reviewed in aggregate has some appeal, a 5 year average of the aggregate gas storage cost accounts might suggest a reduction of over $250,000. In the

Commission's view, Staff's proposed reductions, while arguably conservative, are reasonable and should be adopted.

15. Gas Account 823 - AmerenIP - Hillsboro

a. Staff's Position

AmerenIP seeks to include in rates as an operating expense an annual inventory adjustment of $1,439,000 at the Hillsboro Storage Field. Staff witness Lounsberry recommends that the Commission deny recovery of this amount. His primary reason for making this recommendation is his belief that AmerenIP, due to the various historic problems it has experienced at the Hillsboro field, can not yet reliably make use of the reservoir information to determine any needed adjustments to the field's inventory.

Mr. Lounsberry states that one of the primary means that a utility has to oversee the operation of its storage field involves comparing the field's inventory to the pressure of the gas in the field. He claims that AmerenIP's failure to operate the Hillsboro field with a constant inventory volume since the field was expanded in 1993 causes a situation where the use of normal oversight practices is not reliable. Staff asserts that this concern is shared by AmerenIP. Staff cites a November 20, 2006 report that Staff says, as a result of replacing the 5.8 Bcf of inventory over the prior 3 years, the hysteresis curve is not stable enough to aid in determining a gas loss correction. According to Staff, 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.

AIU argues that in 2006, AmerenIP developed an engineering estimate of the magnitude of losses at Hillsboro. AIU reports that this estimate showed that 200,000 Mcf was appropriate to maintain Hillsboro performance. Subsequent to developing the 2006 estimate, AIU states that AmerenIP conducted additional analysis in 2007 that verified the 2006 estimate was appropriate. According to Staff, in making this latter calculation, called the Tek Methodology, AmerenIP compared the total gas in the reservoir at the end of the 2001 withdraw season to the total gas in the reservoir at the end of the 2006 withdraw season. This calculation was then divided by 5 (for five seasons between the values) and showed a loss amount of 2.29 Bcf, or a loss of about 460,000 Mcf per cycle, or roughly double the 200,000 Mcf loss correction AmerenIP calculated. AIU also indicates that the same calculation was made between 2001 and 2008 and showed about a 340,000 Mcf gas loss per cycle.

Mr. Lounsberry believes that AmerenIP is making its conclusion based on data that compares data points for a time period when the Hillsboro field's inventory was greatly reduced to a more recent period for when Hillsboro had additional inventory. Staff believes the timing of AmerenIP's calculation is causing it to rely upon an apples-to-oranges comparison rather than a comparison that would take place once AmerenIP replaced the inventory in the Hillsboro field. Staff notes that AmerenIP's calculation compared 2001 to 2006 data as well as 2001 to 2008 data. Staff states that AmerenIP

had previously concluded that the inventory balance that it maintained at the Hillsboro field was overstated by 5.8 Bcf as of November 30, 2003. AmerenIP replaced this inventory over a 3-year period, 2003-2005. Staff says AmerenIP also claimed to have found a 1.1 Bcf error that it returned to the Hillsboro field during the 2007 injection season. Therefore, Staff argues, AmerenIP is using inventory numbers for 2001 that bear no relationship with either the 2006 or 2008 values due to the extremely large amounts of gas replaced during the intervening period.

Staff also contends that in 2001, the Hillsboro field was not even functioning properly. Staff states that AmerenIP had reduced the peak day capacity rating of the Hillsboro field to 100,000 Mcf per day from 125,000 Mcf per day. Staff also says that due to the inventory shortfall, the Hillsboro field could only produce a fraction of the seasonal quantities it was designed to produce, 2,916,351 Mcf instead of 7,600,000 Mcf or 38.37% of its design total. According to Staff, AmerenIP's attempt to use 2001 data for comparative purposes does not make sense and should be disregarded.

AIU agrees that AmerenIP's comparison occurred during periods when inventory was reduced. AIU also provides the same Tek Methodology analysis, but limited it to comparing the 2006 to 2008 time period. AmerenIP claims this second comparison is generally in agreement with the original 2001 to 2006 comparison. AmerenIP insists that this analysis supported its decision to add about 200,000 Mcf of inventory to the Hillsboro field in 2006.

Staff maintains that the calculation comparing 2006 to 2008 information, still did not account for the 1.1 Bcf that was added into the Hillsboro field inventory in 2007. Staff also states that AmerenIP's analysis relies upon the gas volume in the field at the end of the withdrawal cycle. According to Staff, a warmer winter season makes it more difficult for a utility to withdraw gas storage volumes from its owned and leased storage fields. Staff argues that, in general, warmer weather creates a situation where more gas is remaining in the field then the utility had planned. Mr. Lounsberry says the 2006 test year conditions were warmer than normal. Staff claims AIU also agrees that winter season temperatures can impact the level of gas that it can withdraw from storage. Staff complains that AmerenIP's calculation does not take into account any temperature conditions. In Staff's view, AmerenIP's analysis is overly simplistic and limited for use at a storage field that has not experienced significant historical inventory losses. Staff does not believe AmerenIP's analysis provides a conclusive demonstration of the need for an annual inventory adjustment at the Hillsboro field.

Mr. Lounsberry also expressed concern that AmerenIP had never determined the need to make an annual inventory adjustment for the Hillsboro field prior to the 2006 test year. His concern is that there was no history of a similar expense and thus no history of a need to make an annual inventory adjustment at the Hillsboro field. AIU agrees that 2006 was the first occasion an annual inventory adjustment was made to Hillsboro, although AIU claims to have made inventory adjustments for a number of years at other storage fields. AIU states that AmerenIP intends to make a similar adjustment for Hillsboro in 2007.

Staff notes that AmerenIP has recently replaced a significant amount of gas at the Hillsboro field. Staff says AmerenIP's replacement gas represents 96% of the gas volume that the Hillsboro field was designed to withdraw during the winter season. Mr. Lounsberry expresses concern that AmerenIP was not making use of the reservoir model that was discussed extensively during IP's last rate proceeding, Docket No. 04-0476. Staff is concerned that such a valuable resource was not used as part of AmerenIP's calculations in this proceeding, especially given the time and money spent to develop this model. Mr. Lounsberry expected AmerenIP to make use of it to develop or support inventory numbers versus calculations based on comparing inventories between two inconsistent time periods. AIU claims the model was not available to evaluate Hillsboro because in 2005, AmerenIP made the determination to not further pursue modeling until a complete metering data set had been established in the reservoir simulator. AmerenIP did not begin to rebuild this database in preparation for resumption of modeling the reservoir until the summer of 2007. Staff complains that it is not clear why AmerenIP was unable to update the metering data set in a more timely fashion.

According to Staff, AmerenIP suggests that Mr. Lounsberry's recommendations are inconsistent with prior proceedings, Docket Nos. 03-0699 and 04-0677, wherein Staff noted that IP should have begun replacement of inventory at the Hillsboro storage while continuing to pursue its investigation as to the cause of the inventory shortfall. Staff says that in those proceedings it argued that had IP been aware of that error in a more timely fashion, it should have replaced some of that known inventory shortfall caused by the metering problem while continuing to investigate if the Hillsboro field had additional problems. Staff fails to see any connection between the instant proceeding and those prior cases. Staff claims that Mr. Lounsberry's testimony and the issue at hand is whether AmerenIP can justify the volume and value of the inventory adjustment that it wishes to make for the Hillsboro field.

b. AIU's Position

AmerenIP proposes an annual inventory adjustment to Account 823 of $1,439,230 for the Hillsboro Storage Field ("Hillsboro"). The adjustment represents AmerenIP's determination to inject additional gas at Hillsboro. AmerenIP claims the proposed adjustment is conservative and based on the best data available to the AmerenIP.

In 2006, AIU states that AmerenIP developed an engineering estimate of the magnitude of gas losses at the Hillsboro field. The results of the estimate indicated that a 200,000 Mcf injection of gas was appropriate in 2006 to maintain Hillsboro's performance. Subsequent to developing the estimate, AIU indicates that in 2007 AmerenIP conducted an additional analysis, using information obtained during the next inject/withdraw cycle, verifying that the estimate it used in 2006 was supportable and prudent. According to AmerenIP, the engineering principles utilized for the 2007 analysis included the Tek Methodology, an analysis of the hysteresis plot for the field,

and a review of field withdrawal performance. AIU claims these are all commonly accepted gas storage reservoir engineering practices.

An additional analysis of reservoir performance, AIU adds, was performed in the spring of 2008 to investigate what impact the injection of additional gas has had on the delivery performance of the Hillsboro field. For this analysis, AmerenIP re-estimated gas loss using the Tek Methodology. According to AmerenIP, the decrease in estimated gas loss from the 2001to 2005 analysis and the 2001to 2008 analysis indicates that the 200,000 Mcf gas loss adjustments that were made in 2006 and 2007 have had a positive impact on maintaining reservoir deliverability. In AIU's view, these analyses showed that AmerenIP's 200,000 Mcf estimate of the gas loss is reasonable and prudent.

AIU argues that there is no dispute that the lost gas should be replaced and Staff does not suggest otherwise. AIU contends that AmerenIP's analysis of the data supports the amount of gas loss and the need for replacement, based on the Tek Methodology. Reinjection of gas to replace lost gas before completion of a thorough engineering analysis of the reservoir response is, AIU claims, consistent with Staff's position in past cases. According to AIU, without the reinjection of the lost gas, field performance at Hillsboro would be at risk, and the field might not be able to cycle the gas required to best meet customer needs. AmerenIP expects that Hillsboro deliverability would decline by approximately 200,000 Mcf per year without reinjection, impacting daily deliverability at the year end. AmerenIP claims that not reinjecting could also cause increased water production and possibly increased H_2S production, further decreasing the reliability of the field. AIU says these factors would ultimately be reflected as a higher cost for ratepayers.

Staff opposes the annual inventory adjustment based primarily on concerns about the reliability of the data supporting the adjustment. Staff believes that AmerenIP does not have sufficiently reliable information about Hillsboro, and can not perform the necessary engineering studies to quantify the gas loss. AIU says Staff recommends doing nothing at this time to address the gas loss issue. AIU maintains that inaction would not be appropriate. AIU believes that AmerenIP should take steps to address the performance of underground fields, such as injecting replacement gas, to maintain reliable service from its storage fields. AIU relates that AmerenIP has calculated annual inventory losses supporting the inventory adjustment at Hillsboro.

At Hillsboro, AIU and Staff acknowledge that an adequate stable inject and withdraw history dataset has not been established that would allow a detailed analysis using hysteresis techniques. AIU asserts that any correction must be based on an engineering estimate, or rely on other sound engineering principles and practices other than hysteresis techniques. AIU asserts that AmerenIP is not required to support its adjustment on a specific type of analysis just because Staff would prefer it. AIU claims that AmerenIP properly relies on the available data, which reasonably supports the adjustment.

AIU argues that Staff's position on the deterioration of storage field performance is inconsistent with a disallowance of an annual inventory adjustment for Hillsboro. AIU asserts that on the one hand Staff supports injecting additional gas to maintain reservoir performance, but on the other hand disallowing the cost of the actions taken by AmerenIP to maintain that performance. It is AIU's opinion that AmerenIP has utilized the best data that is available to make a sound engineering judgment regarding the Hillsboro lost gas adjustment and AmerenIP has taken proactive steps to maintain the field's deliverability.

According to AIU, Staff has recommended, in previous proceedings, that a gas utility take action to correct an inventory shortfall even when data is not complete. AIU says that in Docket Nos. 03-0699, 04-0677, and 05-0743, Mr. Lounsberry argued that IP did not act fast enough to replace the gas at Hillsboro that was no longer in the field. In those cases, AIU says Mr. Lounsberry's position was that the utility should have been replacing inventory while continuing to pursue its investigation as to the cause of the inventory shortfall. In this case, Mr. Lounsberry states that AmerenIP should not use available data to proceed to make an adjustment, even though AmerenIP has calculated its inventory adjustment based on the best available data and is continuing to gather data to improve the estimate.

With regard to Staff's specific concerns, AIU believes these have been adequately addressed. In response to Staff's concern that comparing 2001 data to 2008 data is not appropriate, AIU says that AmerenIP undertook an analysis using data from 2006 - 2008 instead of comparing to 2001. AIU claims the results of this analysis were consistent with the analyses comparing 2001 to 2006 and 2008, and showed that there is an annual gas loss occurring at Hillsboro of slightly less than 0.5 Bcf per year. According to AIU, the original calculations utilizing a 2001 data comparison indicate that from the time period from 2001–2006, the gas loss was 468,000 Mcf per year and from 2001–2008, the gas loss was 337,000 Mcf. AIU insists that AmerenIP is justified in making a conservative adjustment of 200,000 Mcf per year.

AIU reports that the Hillsboro field cycled 6.7 Bcf of gas in 2005–2006 and 6.6 Bcf in 2007–2008. AIU claims that if AmerenIP had not injected an additional 200,000 Mcf during the 2006 and 2007 injection seasons, it is reasonable to assume AmerenIP would not have been able to withdraw roughly equal amounts of gas during the two seasons that are compared.

Mr. Lounsberry also opposes the annual inventory adjustment at Hillsboro based on the concern that annual adjustments were not made before the 2006 test year, raising concern that there is not a history of similar expenses for Hillsboro. AIU states that Mr. Lounsberry is correct that 2006 is the first occasion that an inventory correction was made to Hillsboro in recent history. AIU claims that AmerenIP has made corrections to storage field inventories on an as-needed basis for many years and has performed inventory corrections on an ongoing basis. In AIU's view, the fact that the first correction at Hillsboro occurred in 2006 does not mean the adjustment is not just and reasonable.

According to AIU, Mr. Lounsberry is correct that the reservoir model would be an appropriate method to determine gas losses. AIU says the reservoir simulator was not available to evaluate Hillsboro because the model data deck had not been updated to include the withdrawal metering corrections from 2000-2007. AIU adds that in 2005 the determination was made not to further pursue modeling until a complete metering data set had been established for the reservoir simulator. AIU states that in the late summer of 2007 AmerenIP began to rebuild the database in preparation for resumption of modeling of the reservoir and that project is still in progress. AIU contends that because the model was not available, other sound engineering techniques were used to determine the gas loss. After the revised data deck is built, AIU states that AmerenIP will model the reservoir and present the results to Staff. AmerenIP recognizes that it is proceeding with modeling utilizing adjusted data, rather than actual field data, but insists the adjusted data is sufficient to support the annual inventory adjustment.

c. Commission Conclusion

AmerenIP proposes an annual inventory adjustment to Account 823 of $1,439,230 for the Hillsboro Storage Field. AIU insists the proposed adjustment is conservative and based on the best data available. AIU contends further that the fact that Staff would prefer some other type of data or study to support the adjustment is not a basis for rejecting the adjustment. Staff's primary reason for opposing the adjustment is due to the various historic problems AmerenIP has experienced at the Hillsboro field. Staff does not yet believe that AmerenIP can reliably make use of the reservoir information to determine any needed adjustments to the inventory at the Hillsboro field.

The Commission again observes that this issue is similar to two issues previously addressed regarding lost gas at the Hillsboro field. In the other two instances, AmerenIP asserts that there has been lost base gas, it has estimated the volume of lost gas, and requests authorization to include the additional base gas in rate base. In this instance, AmerenIP asserts there is lost gas at Hillsboro, it has estimated the volume of lost gas, and it wishes to recover the cost of replacing the lost gas through operating expenses. In all three instances, Mr. Lounsberry objects to AmerenIP's request. Mr. Lounsberry again insists, among other things, that AmerenIP has failed to adequately demonstrate that its estimate of the volume of lost gas is reasonable or appropriate. Just as it did in Docket No. 04-0476, as well as for the two previous lost gas issues in this case, the Commission finds Mr. Lounsberry's expert testimony to be convincing. The Commission concludes that AIU failed to adequately demonstrate that AmerenIP's estimate of the lost gas is reasonable. As a result, the Commission adopts Staff's recommendation and AmerenIP's request to recover the replacement gas through Account 823 is denied. In the Commission's view, these three decisions regarding lost gas at Hillsboro are consistent with, and are required by, the appellate court decision discussed earlier in this Order.

16. Gas Accounts 920-923 - AmerenIP

a. The AG and CUB's Position

The AG and CUB propose an adjustment to reduce the pro forma AmerenIP A&G expenses by $7,736,000. In analyzing the expenses associated with the general administration of operations, AG/CUB witness Effron believes that it is appropriate to consider expenses charged to Account 923 "Outside services employed" together with expenses charged to Accounts 920-922, which are compensation to management employees and other expenses of administrative departments. Mr. Effron testifies that expenditures charged to Account 923 for outside professional services can be similar in nature, except the expenditures are to persons who are not employees. For example, salaries of attorneys or engineers who are employees would be charged to Account 920, while expenditures on outside attorneys or engineering consultants would be charged to Account 923. In both of these cases, the AG and CUB say the expenses relate to the administration of the operations of AIU and, to some extent, may be interchangeable. Mr. Effron proposes to adjust AmerenIP's gas test year A&G expenses charged to Accounts 920-923.

The AG and CUB point out that in 2004, the test year in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), the pro forma expenses included in Accounts 920-923 by AmerenIP were $22,259,000. The Commission eliminated approximately 30% of the AmerenIP A&G expenses from the revenue requirement in that case. The AG and CUB say the Commission's A&G adjustment was not broken out by account, but assuming that the adjustment was spread evenly over all the A&G accounts, the AmerenIP revenue requirement in its last rate case reflected an allowance of $15,476,000 charged to Accounts 920-923.

The AG and CUB claim the A&G expenses charged to Accounts 920-923 in the 2006 test year in the present case significantly exceed the expenses found to be reasonable by the Commission in AmerenIP's last rate case. Thus, the AG and CUB believe that the expenses allowed by the Commission in the prior rate case form a reasonable basis for A&G expenses to be included in the AmerenIP revenue requirement in this case. Thus, Mr. Effron's recommendation is to reduce the pro forma AmerenIP A&G expense by $7,736,000 as reflected in AG/CUB Ex. 4.0 at 9-10.

b. AIU's Position

AIU believes an adjustment to the A&G expense is not warranted. AIU asserts that Mr. Effron's methodology for determining his proposed adjustment to the A&G expense is flawed. AIU witness Adams explains that, in calculating his adjustment, Mr. Effron uses as a starting point the level of A&G expenses charged to Accounts 920 through 923 approved by the Commission in AIU's last gas rate cases, which used a 2004 test year. Mr. Effron calculates this amount by taking the total of A&G costs related to Accounts 920 through 923 times the percentage of costs that were disallowed. AIU says he then escalates this last approved level of A&G expenses

charged to Accounts 920 through 923 by 3% per year to reflect inflation. The end result of Mr. Effron's initial adjustment is the proposed disallowance of $19,794,000 of A&G expenses for AmerenIP. AIU says this is the difference between the amount approved in the last rate case, escalated by inflation, and the expenses included by AmerenIP in this case, for Accounts 920 through 923.

AIU argues that the Commission has rejected the notion that inflation between rate cases is a better indication of test year expenses than the actual costs themselves. AIU says Mr. Adams' rebuttal testimony explains the modification of accounting practices implemented after the acquisition of IP by Ameren. AIU points out that thereafter, Mr. Effron reduces his proposed adjustment by $7.7 million. AIU claims the actual level of AmerenIP's A&G expenses have been fully justified between the AMS study which Mr. Adams sponsored and through his testimony on the topic of A&G expenses.

AIU claims Mr. Adams explains that the comparison of the level of expenses between 2004 and 2006 for AmerenIP produces specious results because during the transition of ownership, AIU received no allocated costs from either its former owner or from AMS. Therefore, AIU asserts that the true cost of services provided is not reflected in the 2004 expense levels.

c. Commission Conclusion

The AG and CUB are correct in asserting that the A&G expenses authorized by the Commission for Accounts 920-923 in the 2004 test year are significantly different than those requested by AIU for the 2006 test year in the present case. However, it appears that the AG and CUB do not adequately consider various changes that have occurred, which may have contributed to an increase in the A&G expense from the last rate case. AIU also provided the Commission with an AMS cost study detailing the test-year 2006 A&G expenses, which the Commission must consider in this case. In addition to inflation, which the Commission believes is a relevant factor, actual costs must also be considered, and AIU has supplied evidence regarding actual costs. Lastly, the Commission believes that the AG and CUB's proposed disallowance does not take into account the effect of the merger when comparing test-year expense calculations, which is significant. The Commission finds that in this case, using an inflation based adjustment to AmerenIP's Account 920 through 923 amounts authorized in the last rate case is inappropriate and must be rejected.

D. Approved Operating Income/Revenue Requirement

Upon evaluating the effects of the determinations made above, the operating statements for AIU's respective service territories for electric and gas delivery services are approved as shown in the Appendices attached hereto.

VI. COST OF CAPITAL/RATE OF RETURN

A. Introduction

A company utilizes various types of investor-supplied capital to purchase assets and operate a business. Utilities typically rely upon long-term debt and common equity, and in some instances preferred stock and short-term debt, to purchase assets and fund operations. The costs of different types of investor-supplied capital vary depending upon a multitude of factors, including the risk associated with the investment. As a result, the proportion of the different types of capital, also known as the capital structure, when combined with the costs of each different type of capital affects the overall or weighted average cost of capital, which is the rate of return a utility is authorized to earn on its net original cost rate base.

The Commission relies on the cost of capital standard to determine a fair rate of return. This cost, which can be determined from the overall rate of return or weighted average cost of capital, should produce sufficient earnings and cash flow when applied to the respective company's rate base at book value to: enable a company to maintain the financial integrity of its existing invested capital, maintain its creditworthiness, attract sufficient capital on competitive terms to continue to provide a source of funds for continued investment, and enable a company to continue to meet the needs of its customers.

These standards are effectively mandated by the landmark U.S. Supreme Court decisions Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield") and Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 391 (1944) ("Hope"). Meeting these requirements is necessary in order for a company to effectively meet the utility services requirements of its customers and provide an adequate and reasonable return to its investors, debt holders and equity holder alike.

B. Capital Structure

1. Common Equity Balances

AIU accepted Staff witness Phipps' miscellaneous adjustments to AIU's common equity balances, including, removal of the unappropriated undistributed subsidiary earnings balance from each utilities' common equity balance, removal of Ameren Energy Resources Generating's Accumulated Other Comprehensive Income ("OCI") from AmerenCILCO's common equity balance, as well as removal of the preferred stock premiums from AmerenIP's common equity balance.

AIU's and Staff's agreed common equity balances for AmerenCILCO and AmerenCIPS are $217,459,214 and $506,691,386; each as of June 30, 2007. AmerenIP's agreed December 31, 2006 common equity balance equals

$1,076,124,965. The Commission finds these common equity balances appropriate and they will be adopted for this Order.

2. Preferred Stock Balances

Staff accepts AIU's proposed June 30, 2007 preferred stock balances for AmerenCILCO and AmerenCIPS. Staff and AIU agree on AmerenIP's December 31, 2006 preferred stock balance. Those agreed upon preferred stock balances are $36,450,067 for AmerenCILCO; $48,974,984 for AmerenCIPS; and $45,786,945 for AmerenIP. The Commission finds that these balances are appropriate and they will be adopted for this Order.

3. TFTN Balance-AmerenIP

Staff and AIU agree that AmerenIP's December 31, 2006 TFTN balance equals $171,533,494. The Commission finds this amount appropriate and will adopt it for this Order.

4. Short-Term Debt Balances

a. AIU's Position

AIU notes that Staff's position is that cash should not be netted against short-term debt to obtain the proper net short-term debt balance. Ms. Phipps argues that netting cash against short-term debt as part of the calculation of the proper amount of short-term debt "is improper because cash is not a part of short-term indebtedness." AIU submits that the proper analysis is whether the capital structure accurately reflects the mix of debt supporting utility assets. AIU is of the opinion that the principal flaw with Staff's approach is that, by failing to net cash against short-term debt, Staff treats cash as a utility asset, serving utility purposes, but then does not include the cash in rate base. AIU submits that this produces a mismatch between the cost of funds supporting assets and the returns those assets earn.

AIU avers that it is holding relatively high cash balances due to AIU's credit standing in the aftermath of the legislative "crisis" involving the 2007 retail electric rate changes, and that AIU requires these cash balances for operating purposes. AIU notes that the cash balances sit in money market accounts, earning standard money market returns, to assure immediate access to the funds. AIU submits that were its credit position better, AIU would not hold cash balances at these levels, and that the utilities are holding these amounts of cash to satisfy their public utility service obligations. AIU claims it has lost same day access to funds and instead has had to rely on bank facility borrowings, which requires a three business day lead time and generally involves a minimum loan term of 30 days, and submits that this has had a considerable effect on the flexibility of managing cash.

AIU is of the opinion that there are two ways to treat the cash balances being held for utility purposes. One is to maintain them entirely outside of the ratemaking process by deducting them from the short-term debt balances, as AIU did. AIU submits that this produces a return on the cash (the money market interest rate) reasonably comparable to (although still less than) its cost (the short-term debt rate). A second alternative, in AIU's opinion, would be for the cash to be included in rate base, and the short-term debt be fully reflected in the capital structure. AIU avers that this approach could produce an excess return, however, because the cash would be earning both the overall cost of capital in rates, plus the money market return. AIU submits that it did not pursue this approach, because of this mismatch of cost and return.

AIU is of the opinion that Staff has elected a third method, which produces a significant mismatch between the cost of financing and the return on the assets being financed. AIU notes that Staff includes the full amount of short-term debt (other than money pool lendings and CWIP) in the utility capital structure, while simultaneously treating the cash as a non-utility asset. AIU submits that this treatment assumes that the cash is supported by a mix of capital equal to the proportion of capital supporting assets in rate base. AIU claims that this results in a conclusion that AIU would raise cash at a cost of roughly 8% and invest it in money market accounts earning roughly 3%. AIU submits that this is not a reasonable treatment proposed by Staff.

AIU argues that, by differentiating between (1) cash on hand funding loans to sister utilities and (2) cash invested in liquid money market funds, Staff is suggesting that there is a fundamental difference between the two scenarios. AIU submits that in reality only a cash management decision differentiates the two, and in both instances, the cash is earning a return elsewhere, and the cost of capital supporting the cash should be consistent with the return.

AIU opines that this same reasoning is consistent with that used in discerning that short-term debt related to CWIP and loans to the money pool should not be included in the capital structure. AIU submits that the same short-term debt funds can not be used simultaneously to support rate base and fund CWIP or be loaned to sister utilities and that this is consistent with Staff's long-standing practice and Commission precedent.

AIU further argues that Ms. Phipps, in her calculation of the twelve-month average of short-term debt, improperly aligns the midpoint of the twelve months with the measurement date of the long-term capital structure components. AIU also submits that Ms. Phipps uses data that goes beyond this measurement date by up to six months. AIU opines that short-term debt balances are the result of costs during the test year/measurement period and that the use of measurement balances beyond this period results in a measurement mismatch between short-term debt and the other capital structure balances. AIU avers that Ms. Phipps must provide more compelling evidence that use of data within the boundaries of the test year/measurement period is not proper. Although the Commission ultimately sided with Staff and this approach in

the most recent case, AIU submits that the language of the ruling was hardly a mandate.

While Staff argues that if a company's cost of capital is constant, short-term debt would not be used to finance cash, AIU submits that all of the components of the capital structure cost more than a company would earn on its cash investments. AIU posits that the cost of debt does not change just because the assets it supports earn a lower return, the cost of debt is set by the governing debt instrument.

AIU notes that while Staff suggests that cash is supported by low-cost equity capital, there is no suggestion where AIU is obtaining low-cost equity at a rate less than the short-term debt rate. AIU posits that Staff is tying cash to equity and only equity, while AIU avers that there is no way to isolate equity and apply it only to cash.

AIU opines that it has shown that the cash is being held for utility purposes, and if the cash is not netted against short-term debt to make it whole, then the cash should be included in rate base. While Staff argues that cash investments already earn a return commensurate with their risk, AIU suggests the problem is that the cash is not earning a return commensurate with its cost.

b. Staff's Position

Staff witness Phipps calculated the following short-term debt balances for the AIU: $82,500,351 for AmerenCILCO; $75,752,646 for AmerenCIPS; and $82,506,936 for AmerenIP; while AIU witness O'Bryan proposed the following short-term debt balances: $15,865,875 for AmerenCILCO; $11,902,241 for AmerenCIPS; and $47,106,782 for AmerenIP. Staff submits that AIU's calculations are flawed because Mr. O'Bryan: 1) used a measurement period that is not centered on the measurement date for long-term capital components, and 2) netted out all cash from short-term debt.

Staff notes that Ms. Phipps adjusted AmerenCILCO's, AmerenCIPS' and AmerenIP's short-term debt measurement periods to have a midpoint that coincides with the measurement date for long-term capital structure components (i.e., June 30, 2007 for AmerenCILCO and AmerenCIPS; December 31, 2006 for AmerenIP), which she alleges better aligns the average balance of short-term debt with the long-term capital structure components. Ms. Phipps opines that the balances of short-term debt and long-term capital structure components can be perfectly aligned only if both are measured on the exact same dates, which would mean measuring the short-term and long-term capital structure component balances either on the same, single date, or as an average of the same 12-month period. She avers that the former has the disadvantage of not smoothing out the variation that often exists in short-term debt balances, while the latter has the disadvantage of being more time consuming and prone to measurement error due to the greater amount of data and calculations involved. Ms. Phipps submits that a reasonable, practical solution to those disadvantages is to measure the long-term capital components on a single date, while

smoothing out the variation in short-term debt by using a 12-month average centered on the measurement date of the long-term capital structure components.

Staff notes that while Mr. O'Bryan argues that Staff's measurement period results in a measurement mismatch between balances of short-term debt and the other capital structure components, Mr. O'Bryan's argument is not pertinent in this case because there were no issuances, redemptions or maturities of equity or debt during those six months beyond AIU's long-term capital measurement dates, which would be included in Staff's measurement period but not AIU's.

Staff opines that a 12-month average centered on the measurement date of AIU's long-term capital structure components minimizes the total number of months that are misaligned. Staff submits that using its methodology, the total misalignment between long-term and short-term capital balances is 42 months, while using AIU's methodology results in a misalignment of 78 months. Staff argues that because the number of months of misalignment in AIU's calculation is greater than Staff's calculation, any measurement mismatch affects AIU's calculations more than it would Staff's.

Staff notes that the Commission adopted Staff's short-term debt balance calculations in Docket Nos. 99-0534, 01-0696, 03-0676/03-0677 (Cons.) and 06-0070/06-0071/06-0072 (Cons.). Staff also cites the Commission's Order in Docket No. 01-0696.

While Staff notes that Mr. O'Bryan argues that short-term debt balances are the result of costs during the test year/measurement period, Staff submits that Mr. O'Bryan's argument is based on the faulty premise that the terms "test year" and "measurement period" are synonymous. Staff notes that 83 Ill. Adm. Code 285.115 specifies that the capital structure measurement period refers to the period or point in time in which all long-term components of the capital structure are measured and may differ from the "test year." Staff further notes that AIU chose June 30, 2007 to measure the balances of long-term debt, preferred stock and common equity for AmerenCILCO and AmerenCIPS, which is six months after the end of the 2006 test year.

Staff submits that the Commission's Order in Docket No. 99-0534 distinguishes between the terms capital structure measurement period and test year when it states:

> . . . the cost of capital, and therefore its components, are not subject to the Commission's test year rules. In Business and Professional People for the Public Interest et al. v. The Illinois Commerce Commission et al., 585 N.E.2d 1032,(December 16, 1991), the Supreme Court found, in part, that, "Because the post--in--service carrying charges are not operating expenses, they are not test—year items. Therefore, we agree with Edison and the Commission that recovery of deferred financing charges does not violate test--year principles." (BPI II at 1060) The implication of the Court's finding is that the balance of short-term debt, as a component of a utility's

authorized rate of return, is not subject to test--year rules. (Docket No. 99-0534, Order at 32-34 (July 11, 2000))

Staff argues that another flaw in Mr. O'Bryan's analysis is his subtraction of cash from each month-end gross short-term debt balance, which Ms. Phipps testified is improper because cash is not a part of short-term indebtedness. Staff's short-term debt calculation does not net out cash; however, it does reduce monthly gross short-term debt balances for each of the Companies by an amount equal to its month-end balance of bank loan contributions to the Ameren utility money pool.

Staff submits that while cash is fungible and can not generally be traced from source to use, nevertheless, a portion of AmerenCILCO's, AmerenCIPS' and AmerenIP's short-term balances appear to coincide with contributions to the Ameren utility money pool. Staff takes the position that in those instances where there is a clear, proximate connection between a company's short-term debt balance and its contributions to the utility money pool, it is appropriate to net money pool contributions out of gross short-term debt to avoid double counting bank loans from Ameren's credit facilities. Staff submits that this ensures that those contributions (which are included in the borrower's short-term debt balances) are not counted twice in both the lender and the borrower's capital structure.

Staff asserts that Mr. O'Bryan's reasoning is faulty in that it implies the cost of capital remains constant regardless of the riskiness of the assets it supports. Staff posits that the costs of the various sources of financing are a function of the riskiness of the assets being financed as well as the amount of debt used to finance the assets. Staff submits that Mr. O'Bryan's rationale suggests that holding the capital structure constant, a company's cost of capital would be the same whether its assets wholly comprised U.S. Treasury bills, electric distribution plant, or oil drilling equipment.

Staff posits that if this held true, companies would not have any cash on their balance sheet unless they also had short-term debt outstanding because it would perforce be financed with "high cost" long-term debt and equity. Staff submits this is not true for AIU. Staff notes that during 2006, from January through November, AmerenCIPS' month-end short-term debt balances were zero; yet, during the same period, AmerenCIPS' month-end cash balances ranged from $0.5 million to $62.5 million. Staff further notes, on May 31, 2007, AmerenCIPS had no short-term debt outstanding and a $44 million cash balance.

Contrary to Mr. O'Bryan's opinion that AIU's capital must be tied to the assets included in rate base, Staff submits that the Commission has recognized that, for ratemaking purposes, a utility's capital structure is not required to equal rate base, but rather, a utility's capital structure must reflect the mix of capital a utility relies upon to finance its rate base. Specifically, in the prior CIPS and UE gas rates proceeding, the Commission's Order states:

> On a utility's financial statements, the total dollar value of assets must equal the total dollars of liabilities and owner's equity. In a rate case, however, the total dollars of jurisdictional rate base does not necessarily equal total capitalization . . . . Due to the fungible nature of capital, it is generally assumed that all assets, including assets in rate base, are financed in proportion to total capital . . . .
>
> The Commission has reviewed the parties' arguments and adopts Staff's proposal for calculating the amount of short-term debt included in UE's capital structure. (Docket Nos. 02-0798/03-0008/03-0009 (Cons.), Order at 65-68 (October 22, 2003))

Staff disputes the notion that AIU is holding relatively high cash balances due to its credit standing in the aftermath of the legislative crisis involving the 2007 retail electric rate changes, and submits that AIU held substantial cash balances prior to March 2007, which is when its issuer credit ratings were downgraded to below investment grade. Staff notes that on March 31, 2007, AmerenCILCO's cash balance equaled $200,000, and AmerenCIPS' cash balance equaled $47 million, while during 2006, AmerenCILCO held cash balances as high as $22 million and AmerenCIPS held cash balances as high as $63 million, excluding loans to utility affiliates through the money pool. Staff further notes that AIU has never identified specific months or amounts that relate solely to its credit rating downgrades, and when the risk of an electric rate rollback and freeze disappeared, AIU's short-term debt balances either increased or stayed approximately the same.

Staff notes that while AIU argues that cash must be netted out of short-term debt balances, Staff submits that AIU's own actions demonstrate otherwise. Staff notes that during August 2006, AmerenCILCO, AmerenCIPS and AmerenIP had net cash balances of $13 million, $77 million and $9 million, respectively. Staff further states that AmerenCIPS and AmerenIP paid common dividends totaling $40 million and $61 million, respectively, during 2007, rather than paying down short-term debt.

While AIU argues that failure to net cash against short-term debt implies that cash should be part of rate base, Staffs submits that cash does not need to be included in rate base because temporary cash investments already earn a return commensurate with their risk. Staff opines that including cash in rate base would increase the amount of the AIUs' rate base; and the rate base including cash would be relatively less risky than rate base excluding cash because there is virtually no risk associated with cash on hand. Staff submits that adding low risk cash to rate base assets would lower the cost of capital, which, combined with including the income on cash investments in the revenue requirement, would exactly offset the higher rate base.

Staff further notes that AIU takes the position that by differentiating between cash on hand funding loans to sister utilities and cash invested in liquid money market funds, Staff is suggesting that there is a fundamental difference between the two scenarios.

Staff submits however, that in reality only a cash management decision differentiates the two.

Staff opines that if AIU's proposed adjustment was for the purpose specified, then such adjustment would have been limited to the period during which AIU built up cash reserves and would have adjusted short-term debt for only the portion of cash AIU alleges it accumulated during that period. Staff notes however, that instead, AIU proposes to subtract the entire cash balance from short-term debt during the entire short-term debt measurement period. Staff notes that for AmerenCILCO and AmerenCIPS, the AIU proposed short-term debt measurement period covers June 30, 2006 to June 30, 2007, for which only four monthly balances out of thirteen occur after the March 2007 credit rating downgrade, and for AmerenIP, the AIU proposed short-term debt measurement period ends three months before the downgrades occurred. Staff avers that under no circumstances would it be reasonable to remove all cash, as AIU proposes to do, since on any given date a utility would likely have cash on hand for operating purposes.

Staff submits that the two alternatives that AIU has offered for the treatment of short-term debt balances have one thing in common, each would result in higher rates charged to ratepayers. Staff recommends that its suggested short-term balances be adopted for the purposes of this Order.

c. Commission Conclusion

AIU argues that it is holding abnormally high cash balances due to each utility's worsened credit situation following the 2007 retail electric rate changes, and suggests that these cash balances should be netted out from short-term debt balances to compute the capital structure for each company. AIU suggests that a second alternative would be to include the cash in rate base, and the short-term debt be fully reflected in the capital structure; however, AIU argues this might produce an excess return for each company as they would be earning a money market rate of return on the cash while also earning the approved return on equity.

Staff takes the position that the total amount of short-term debt should be reflected in the capital structure and that cash balances should not be netted out from the balances. Staff notes that cash is fungible and generally can not be traced from source to use, however it appears to Staff that a portion of each utilities' short-term debt balances coincide with contributions to the Ameren utility money pool. Staff suggests where there is a clear connection between the short-term debt and its contribution to the money pool, it is appropriate to net those contributions out of short-term debt to avoid double counting. Staff disputes that AIU is holding relatively high cash balances solely due to its credit standing, and notes several instances where one of the utilities held high cash balances prior to the retail electric rate crisis and the downgrade in each utilities credit rating.

The Proposed Order in this proceeding adopted AIU's proposed short-term debt balances rather than Staff's proposed balances. In its Brief on Exceptions, Staff maintains that cash balances should not be subtracted from short-term debt balances and that its proposed measurement period for short-term debt balances should be adopted rather than AIU's proposal. Staff, however, also provided several alternatives for the Commission's consideration in the event it rejected Staff's primary position. Specifically, using data presented in Staff Group Ex. 3, Staff presented information that would allow the Commission to combine Staff's measurement period for short-term debt balances with Staff's measurement proposal, with AIU's measurement proposal, and with a measurement approach that would remove only "excess" cash balances from the short-term debt balances.

As an initial matter, it appears from the record that neither the AIU proposal nor the Staff primary proposal is perfect and that each has raised valid concerns or criticisms of the other. All things considered, the Commission believes that Staff's suggested approach to remove excess cash from short-term debt balances, along with the adoption of Staff's measurement period, appears to be the approach best supported by record evidence. Upon consideration of all the evidence presented, the Commission finds that AIU has not justified subtracting the entire cash balance during the entire short-term debt measurement period. The Commission finds convincing Staff's argument that, in no event, should all cash be subtracted from the short-term debt balances. The record clearly indicates that AIU used short-term debt for purposes unrelated to the requirements that it hold unusually high balances. Thus, the suggestion of removing the "excess" cash is the most reasonable. Staff also suggests that it would be inappropriate, considering AIU's loss of same-day access to funds, to potentially enrich AIU through a higher authorized rate of return due to its affiliates' decision, which AIU disputes, to withhold financial support. While the Commission is always observant of such possible actions, as theorized by Staff, it does not appear that the record nor the arguments presented by the parties have been fully developed in this proceeding. In any event, the Commission notes that this issue was not a significant factor in the Commission's decision on the appropriate amount of short-term debt to include in the capital structure for AIU.

It appears to the Commission that, at least for a portion of Staff's short-term debt measurement period, AIU has been keeping higher than normal cash balances due to its relatively low credit rating, which resulted from the perceived electric rate crisis. The Commission agrees with Staff's assertion that in no event should all cash balances be subtracted from the short-term debt balances. As such, the Commission is of the opinion that adopting Staff's calculation of short-term debt, which removes "excess" cash is superior to AIU's proposal to remove all cash from short-term debt, and it is adopted for purposes of this docket.

The final issue with regard to short-term debt balances is whether the average balances of short-term debt should be centered upon the capital structure measurement date as Staff recommends, or should end at the same date as the capital structure measurement period as AIU recommends. The Commission notes that AIU's proposed

short-term debt measurement period for AmerenIP ends three months before the March 2007 credit rating downgrades and, further, only a portion of AmerenCIPS' and AmerenCILCO's proposed measurement periods are after the credit downgrades. The Commission also notes that this issue is the same as that litigated in AIU's last rate case (Docket Nos. 06-0070/06-0071/06-0072 (Cons.)). The Commission has reviewed the record on this issue and again concludes that Staff's approach is superior to AIU's. The Commission notes that this issue is significant to the final calculation of the appropriate cost of equity. As illustrated by Staff's testimony, all else being equal, to use AIU's proposed measurement period in Staff's cost of capital recommendation, would cause the overall cost of capital to increase 54 basis points for AmerenCILCO, 20 points for AmerenCIPS, and 8 basis points for AmerenIP. The Commission also observes that in the South Beloit Water, Gas and Electric Company's rate case in Docket Nos. 03-0676/03-0677 (Cons.), the Commission adopted the approach advocated by Staff in this proceeding. The Commission will therefore adopt Staff's measurement period for calculating short-term debt balances in this proceeding. The conclusions reached in this portion of the order lead the Commission to adopt short-term debt balances of $72,643,527, $55,210,979, and $76,677,769 for AmerenCILCO, AmerenCIPS, and AmerenIP, respectively.

5. Long–Term Debt Balances

The Commission notes that Staff recommends the following long-term debt balances for AIU: $141,064,706 for AmerenCILCO; $446,741,385 for AmerenCIPS; and $709,096,036 for AmerenIP; while AIU proposes the following long-term debt balances: $141,064,013 for AmerenCILCO; $445,904,162 for AmerenCIPS; and $704,808,159 for AmerenIP. It appears to the Commission that despite the very minor differences between AIU and Staff, the resolution of this issue will be determined by the Commission decisions in the following parts of this Order; Embedded Cost of Long-Term Debt – AmerenIP, Embedded Cost of Long-Term Debt – AmerenCIPS, and Embedded Cost of Long-Term Debt – AmerenCILCO.

C. Cost of Debt

1. Short-Term Debt

AIU updated its cost of short-term debt to conform with Staff's calculations, and for purposes of this case, accepted Ms. Phipps' weighting methodology used to calculate the cost of short-term debt for AIU. This weighting methodology determined a spread over the London Inter-Bank Offer Rate index to calculate AIU's cost of short-term debt. The agreed upon costs of short-term debt are 4.04% for AmerenCILCO, 4.01% for AmerenCIPS, and 3.93% for AmerenIP.

IIEC witness Gorman recommended a reduction to AIU's cost of short-term debt. IIEC notes that AIU reduced its short-term cost to recognize more recent lower interest rates, and IIEC does not contest this issue further. The Commission finds the agreed

costs of short-term debt for each company to be appropriate, and they will be adopted for the purposes of this Order.

2. Variable Rate Long-Term Debt

AIU accepted Ms. Phipps' interest rates for AmerenCILCO and AmerenCIPS Series 2004 auction rate pollution control bonds ("PCBs"). Ms. Phipps used interest rates from the last auctions prior to the December 2007 rating agency actions that affected the bond insurers that insured these PCBs. This, in turn, had a negative effect on the interest rates of the PCBs. AIU submits that although this is a reasonable approach to treat the cost of these bonds, this approach should not be used with respect to the AmerenIP auction rate PCBs. The agreed upon interest rates are 4.10% for AmerenCILCO's $19.2 million auction rate PCBs and 4.25% for AmerenCIPS' $35 million auction rate PCBs. The Commission finds these rates to be appropriate, and they will be adopted for the purposes of this Order.

3. Embedded Cost of Long-Term Debt for AmerenCILCO

For AmerenCILCO, Staff witness Phipps calculated a 6.65% embedded cost of long-term debt while AIU calculated a 6.67% embedded cost of long-term debt. The difference between those calculations relates to the annualized interest expense for AmerenCILCO's auction rate PCBs. AIU accepted Staff's proposed 4.10% rate for AmerenCILCO's auction rate PCBs, but Staff notes that AIU failed to update its long-term debt schedule to reflect Staff's proposal. As such, Staff believes the Commission should adopt Staff's calculation of AmerenCILCO's embedded cost of long-term debt, as presented in Staff Ex. 4.0R, Sch. 4.03 CILCO. AIU indicates it does not contest Staff's long-term debt rate for AmerenCILCO. The Commission finds Staff's suggested embedded cost of long-term debt for AmerenCILCO to be appropriate and it will be adopted for the purposes of this Order. The Commission understands that as a result, the proper balance of long-term debt to be adopted for AmerenCILCO is $141,064,706, as Staff recommends.

4. Cost of AmerenIP's Transitional Funding Trust Notes

a. AIU's Position

AIU witness O'Bryan employed an internal rate of return ("IRR") method to determine the embedded cost of the AmerenIP TFTN. AIU opines that the IRR method is appropriate for determining the cost of this debt because AmerenIP does not have economic use of the entire amount of net proceeds of the TFTN between the issuance date (December 1998) and the final maturity date (December 2008). AIU submits that the use of the IRR method to determine the cost of TFTNs was approved by the Commission in the 1999 and 2001 electric delivery services tariff cases as well as the 2004 gas rate case.

AIU argues that Staff witness Phipps incorrectly suggests that the TFTN coupon rate should not be calculated using an IRR monthly compounded methodology. AIU submits that Ms. Phipps' argument to annualize the monthly discount rate by multiplying the rate by twelve is based on the faulty assumption that the Instrument Funding Charges ("IFC") collections are remitted by AmerenIP to the indenture trustee on a monthly basis, which is not true in this case. AIU claims that AmerenIP remits funds to the trustee on a daily basis, and those funds are unavailable to the company once remitted. AIU is of the opinion that Ms. Phipps' means of calculating the TFTN cost understates the true cost to AmerenIP.

AIU also notes that while Ms. Phipps claims that Mr. O'Bryan incorrectly included an additional year of cash flows in the IRR analysis, AIU opines that these cash flows must be included in the IRR analysis, as they make up the test year cost calculations. AIU notes that unlike the balance of TFTNs, which is a capital structure component and must be measured as of the end of the test year, the IRR calculates the true cost of the TFTNs and must incorporate the full test year cash flows. AIU further notes that while Ms. Phipps adjusted the amount of "Net Proceeds Used to Retire Principal" to reflect a $100,000 subtraction to the capital subaccount, stating that Mr. O'Bryan did not include this in his calculations. However, according to AIU, Mr. O'Bryan did include this subtraction in the last line of the "Collection Amount" column in the IRR spreadsheet, and AIU submits that this amount is embedded in his IRR calculation.

b. Staff's Position

Staff witness Phipps calculated that AmerenIP's embedded cost of TFTNs equals 4.92%. Ms. Phipps then made three adjustments, which reduced the TFTN IRR to 4.5% in comparison to AmerenIP's 5.6% IRR calculation.

Ms. Phipps adjusted the IRR analysis to begin on AmerenIP's proposed December 31, 2006 capital structure measurement date, as Staff submits that AIU's analysis incorrectly includes one additional year of cash flows because the IRR calculation begins January 1, 2006. Staff opines that calculating the cost of the TFTNs using data beginning January 1, 2006 overstates the cost of debt due to the twelve months of additional cash flows that represent the present value of the TFTN collection amounts during 2006. Staff notes that adjusting the IRR analysis by changing the measurement period to include one additional year of cash flows increases the IRR by approximately one percentage point (1.0%), and increases AmerenIP's overall cost of capital by approximately 8 basis points.

Staff submits that it is appropriate to calculate the TFTN cost as of the capital structure measurement date and that to include the 2006 cash flows in the TFTN IRR analysis would be incorrect. Staff notes that AIU chose the higher January 1, 2006 IRR (i.e., approximately 5.6%) rather than the lower December 31, 2006 IRR (i.e., approximately 4.5%) and combined it with the lower December 31, 2006 balance of TFTNs ($172,800,000) rather than the higher January 1, 2006 balance of TFTNs ($259,200,000). Staff submits that AIU's IRR calculation violates the present value

principle on which it rests: the value of an asset equals the cumulative value of its future discounted cash flows.

Staff further adjusted the TFTN IRR analysis by increasing the amount of "Net Proceeds Used to Retire Principal" by $100,000 as the TFTN prospectus indicated the Trust retained $4,220,000 of TFTN sale proceeds in the capital subaccount rather than the $4,320,000 amount AIU's calculation assumes. Staff avers that although Mr. O'Bryan correctly modeled that $4,220,000 from the capital subaccount will be returned to AmerenIP in December 2008, he incorrectly modeled that $4,320,000 of the TFTN proceeds were deposited in the Capital Subaccount in December 1998. Staff submits that failing to make this adjustment results in an artificially low amount of cash available to retire the TFTNs, thereby inflating the results of the TFTN IRR analysis.

Staff notes the TFTN coupon rate is calculated using an analysis that finds the monthly discount rate that equates the cumulative present value of the monthly cash servicing costs of the TFTNs to the principal outstanding net of over-collateralization. Staff submits that while AmerenIP calculated an annual discount rate that reflects monthly compounding, Staff calculated the monthly discount rate and multiplied it by twelve to annualize it.

Staff opines that while annualizing a periodic rate of return by compounding it to the power equal to the number of periods in a year is necessary for determining the required rate of return from the perspective of investors, the cost of TFTNs is embedded; that is, the cost of TFTNs is calculated from the perspective of the utility, not investors. Staff submits that embedded costs are annualized by multiplying the periodic rate by the number of periods in a year.

While AIU argues that annualizing the monthly discount rate used in the IRR calculation, rather than compounding it, understates the true cost to the utility because AmerenIP remits funds to the TFTN trustee on a daily basis, Staff avers that AIU's monthly compounding in the IRR calculation overstates the embedded cost of TFTNs and should be rejected. Staff submits that the payment timing difference of TFTNs is more properly accounted for using a working capital adjustment than a cost of capital adjustment. Staff's proposed working capital allowance for AmerenIP includes this adjustment to reflect the timing difference between AmerenIP's TFTNs and its other long-term indebtedness, which AIU witness Adams testified was appropriate.

Staff notes that in AmerenIP's prior electric delivery service rate case (Docket Nos. 06-0070/06-0071/06-0072 (Cons.)), Staff's proposed working capital allowance included a 91.5-day lead for conventional debt and a two-day lead for TFTNs, which was accepted by the Commission. Staff submits that its proposed treatment of the AmerenIP TFTN notes is appropriate, and AIU's suggestion that the IRR calculation requires monthly compounding should be rejected.

Staff notes that while AIU takes the position that its method of calculating the IRR to determine the cost of TFTN was approved by the Commission in the 1999 and 2001

electric DST cases as well as the 2004 gas case, Staff submits that the Orders for AmerenIP's 2001 DST case and 2004 gas case do not describe the TFTN cost calculation and can not be relied upon to support AmerenIP's IRR methodology as Staff and IP stipulated to an overall cost of capital, including a TFTN cost rate. Staff further notes that in IP's 1999 DST case, Staff and IP agreed upon the TFTN cost rate, but the Order does not describe the TFTN cost calculation.

Staff opines that the use of IRR analysis to calculate the TFTN cost was not contested in the previous case (i.e., Docket Nos. 06-0070/0071/0072 (Cons.)) and is not contested in the instant case. Staff notes that in both cases, Staff and AmerenIP calculate the TFTN cost rate using IRR analysis. In both cases, to calculate the annual IRR, Staff multiplies the monthly IRR by 12, while in contrast, AmerenIP compounds the monthly IRR. Staff further avers that in the 2006 IP DST case, the Commission concluded that Staff's method for calculating the embedded cost of TFTNs was correct.

c. Commission Conclusion

The Commission notes that this issue appears to be the same as was litigated in AIU's last DST case. The Commission has reviewed the record on this issue and again concludes that Staff's method for calculating the embedded cost of TFTNs is correct. The cost of long-term debt, including TFTNs, is known with relative certainty and should be calculated on an annual basis. Multiplying the stated monthly rate by 12 produces an annualized embedded cost that is consistent with the entire test year revenue requirement calculation. Additionally, AIU's concern about the economic impact of frequent remittance by AmerenIP to the trustee is recognized in the CWC allowance adopted in this Order. The Commission finds that Staff's method for calculating the interest rate for AmerenIP's TFTNs when combined with the appropriate CWC calculation properly reflects AmerenIP's cost of providing service. The Commission finds Staff's estimate of AmerenIP's embedded cost of TFTNs, 4.92%, to be reasonable for purposes of setting rates in this proceeding.

5. AmerenIP's Embedded Cost of Long-Term Debt

a. AIU's Position

AIU witness O'Bryan updated AmerenIP's long-term debt schedule to reflect the recent refinancing of its auction rate PCBs. AIU notes that on April 8, 2008, AmerenIP issued $337 million of senior secured notes for the purpose of redeeming AmerenIP's outstanding PCBs that were in auction rate mode. AIU submits that the parties agree that negative credit rating actions against the bond insurers starting in December 2007 caused rates to spike in the auction rate market. AIU notes that rates on these securities, which were in the range of 1.54% - 3.93% over the period 2004-2007, saw rates climb to as high as 18%. Due to the extremely high rates on these securities recently, AIU states that Ms. Phipps measured these rates using the interest rates from the last auctions prior to the December 2007 rating actions by Moody's Investors Service ("Moody's") and S&P on the companies that insure the AIU's auction rate PCBs.

Ms. Phipps reasoned in direct testimony that one possible outcome was the refinancing of these securities due to the recent authority the Commission granted AmerenIP to do so. AIU notes that AmerenIP did refinance these securities, and as result, AIU submits that Ms. Phipps' proxy rates should be updated for actual rates that reflect AmerenIP's true amount and cost of long-term debt for the foreseeable future.

AIU submits that this updating of AmerenIP's long-term debt schedule to reflect the refinancing of its auction rate PCBs should not be considered a selective update, and notes that Ms. Phipps contemplated such a scenario in her direct testimony. AIU avers that the rates that she used were a proxy for the true rate on the PCBs and should be considered a short-term substitute until a more permanent rate can be used which would reflect the truer cost of the capital. AIU submits that that rate is now available, and given this special situation should be viewed as more appropriate than Ms. Phipps' proxy rate.

AIU's suggests that its proposed replacement of a proxy that Staff developed in light of market turmoil, with the cost of the now-known permanent replacement is appropriate and should not be considered by the Commission to be a selective update.

b. Staff Position

Staff submits that as of December 31, 2006, AmerenIP's balance of long-term debt equals $709,096,036, and the embedded cost of long-term debt equals 7.34%.

AmerenCIPS, AmerenCILCO and AmerenIP each have outstanding variable rate long-term indebtedness in the form of PCBs with interest rates established every 7 or 35 days through an auction (the "auction rate PCBs"). The parties agree that during December 2007, Moody's placed the credit ratings of the companies that insure those auction rate PCBs on review for possible downgrade and S&P assigned the ratings of those bond insurance companies to Negative CreditWatch or assigned their ratings negative Outlooks, and that those negative credit rating actions preceded a dramatic increase in the interest rates for the auction rate PCBs.

In her direct testimony, Ms. Phipps stated that during the period rates set in this proceeding are in effect, one of two events is likely to occur: 1) the market for insured tax-exempt bonds will return to a more stable equilibrium in which interest rates on such indebtedness reflect the risks of default, or 2) AIU will refinance the auction rate PCBs. Ms. Phipps testified that the results of the last auctions available at the time she filed direct testimony were not reasonable estimates of the rates AIU will incur on the associated indebtedness in either of those events. Ms. Phipps indicates she estimated the cost of the auction rate PCBs using the interest rates from the last auctions prior to the December 2007 rating actions by Moody's and S&P on the companies that insure AIU's auction rate PCBs.

Specifically, Ms. Phipps recommends using the following interest rates for AmerenIP's auction rate PCBs: 4.865% for AmerenIP's $150 million auction rate PCBs;

4.571% for AmerenIP's $111.77 million auction rate PCBs and 5.857% for AmerenIP's $75 million auction rate PCBs. Staff notes that AIU accepted Staff's cost estimates for AmerenCILCO's and AmerenCIPS' auction rate PCBs, which Staff says were derived in the same manner as Staff's cost estimate for AmerenIP's auction rate PCBs, however AIU did not accept Staff's interest rate for AmerenIP's auction rate PCBs.

Staff submits that AIU proposes a selective update to AmerenIP's long-term debt schedule to reflect the April 2008 refinancing of AmerenIP's auction rate PCBs by removing $336.77 million auction rate PCBs, including $337 million of 6.25% Senior Secured Notes, and reflecting March 31, 2008 balances of unamortized loss for the reacquired PCBs only, which is fifteen months beyond the December 31, 2006 balances for every other long-term debt issue. Staff submits that this selective update effectively increases the embedded cost of the PCB-related indebtedness by approximately two percentage points (from 4.6% to 6.5%) and increases the embedded cost of debt for AmerenIP from 7.14% to 7.98%. Staff opines that AIU's selective update to AmerenIP's long-term debt schedule provides neither an accurate nor complete view of AmerenIP's cost of capital on either December 31, 2006, or during April 2008.

Staff recommends against allowing selective updates to AmerenIP's cost of capital. Should the Commission determine it would be appropriate to update IP's cost of capital to reflect the 6.25% interest rate Senior Secured Notes AmerenIP issued to redeem its auction rate PCBs, Staff recommends the Commission also update the costs of variable rate debt issues (short and long-term) and the cost of common equity, leaving the capital structure balances unchanged. Further, since AmerenCILCO and AmerenCIPS also refinanced PCBs during April 2008, Staff submits that their variable rate debt and common equity costs should be updated as well.

Ms. Phipps testified that the updated cost of short-term debt for AmerenCILCO, AmerenCIPS and AmerenIP are 3.95%, 3.92% and 3.74%, respectively, and the updated cost of long-term debt for AmerenCILCO, AmerenCIPS and AmerenIP are 6.63%, 6.24% and 7.94%, respectively. Staff submits that for AmerenCILCO and AmerenCIPS, the updated interest rate for auction rate PCBs equal their respective updated short-term debt cost, while for AmerenIP, the updated interest rate for auction rate PCBs equals 6.25%, which is the interest rate for the Senior Secured Notes that AmerenIP issued in April 2008 to replace auction rate PCBs.

Should the Commission determine it is necessary to update the AIU's cost of capital estimates due to recent financing activity in connection with redeeming and refinancing auction rate PCBs, then Staff submits that the cost of capital for AmerenCILCO's, AmerenCIPS' and AmerenIP's gas delivery services operations would be 7.94%, 8.14%, and 8.90%, respectively. Those cost of capital recommendations reflect Staff witness Freetly's updated 10.73% cost of equity estimate for the utilities' gas delivery services operations. Staff asserts that the updated cost of capital for AmerenCILCO's, AmerenCIPS' and AmerenIP's electric delivery services operations would be 7.75%, 7.94%, and 8.69%, respectively. Those cost of capital

recommendations reflect Ms. Freetly's updated 10.32% cost of equity estimate for the utilities' electric delivery services.

Staff states that in AIU's 2006 electric delivery services rate case, the Commission noted the risks inherent in selective updates to capital structure components, rejected AIU's proposed selective updates to interest rates, and endorsed measuring all the costs of capital at or over the same period. Staff opines that AIU's attempted change in the auction rate PCB's also changes costs and balances included in AmerenIP's embedded cost of long-term debt and ignores AmerenIP's other recent financing activity and changes to other capital structure costs and balances that occurred between December 31, 2006 and April 2008. Staff avers that until the conclusion of AmerenIP's next rate case, Staff's proposed cost of debt will be more than sufficient to cover the additional interest expense AmerenIP incurs on its new bonds relative to the interest expense of its auction rate PCBs.

Staff recommends its calculation of AmerenIP's embedded cost of long-term debt be adopted and AIU's selective update should be rejected. Should however, the Commission adopt AIU's calculation of the embedded cost of long-term debt, Staff submits that the Commission should adopt Staff's alternative cost of capital recommendations for AmerenCILCO, AmerenCIPS and AmerenIP. Despite the flaws inherent in Staff's alternative recommendations for AIU, Staff insists they are superior estimates of the cost of capital in comparison to AIU's selective update to AmerenIP's long-term debt schedule because they provide a more complete and more accurate view of AIU's cost of capital.

c. Commission Conclusion

The Commission notes that it has generally endorsed the principal of measuring all of the costs of capital at or over the same period. The Commission is of the opinion that such an approach generally contributes to a test year revenue requirement that matches the cost of providing services and, in the Commission's view, is fair to both consumers and the utility investors. As the Commission noted in AIU's last delivery services case:

> The Commission becomes wary when a party proposes updates to certain components of the cost of capital without providing updates to all components. Allowing selective updates could serve to encourage utilities to only provide updates if the cost of components increased. Absent sufficient justification, this would be unfair to ratepayers… (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 109)

The parties are in agreement that an outside event affected the credit markets, and resulted in interest rates on auction rate PCBs that were far higher than the interest rates typically associated with those PCBs. It appears to the Commission that both parties have presented an adjustment to the actual interest rate incurred in the December, 2007 auction of AmerenIP PCBs, one prospective and one retrospective,

and the question presented is whose update is more appropriate. The Commission is concerned that AIU's proposed use of the actual results from the April 8, 2008 refinancing does not take into consideration other relevant changes to AIU's cost of capital components and might be considered a selective update. The fact that Staff, in the event the Commission adopts an update to AmerenIP's PCB cost, recommends multiple other changes to components of cost of capital, verifies that the selective update concern is warranted.

Given that the cost of capital changes constantly, the Commission is reluctant to start down a path of selective updates or continuous updates during the pendency of a rate case. The Commission further notes that AIU has accepted Staff's proposed method for calculating the interest rates associated with AmerenCIPS' and AmerenCILCO's PCBs. Staff indicates it made those calculations in a similar manner to Staff's proposal for AmerenIP and that AmerenCIPS and AmerenCILCO also refinanced the auction rate PCBs in April 2008. The Commission is concerned that AIU fails to explain why the AmerenIP PCBs should be treated differently than the AmerenCIPS and AmerenCILCO PCBs.

Thus, the Commission finds that AIU's proposal to update the cost of AmerenIP's PCBs should be rejected. For purposes of this proceeding, the Commission finds Staff's original estimate of AmerenIP's embedded cost of debt, 7.34%, and its proposed balance of long-term debt, $709,096,036, to be reasonable for purposes of setting rates in this proceeding.

6. AmerenCIPS' Embedded Cost of Long-Term Debt

The parties are in disagreement over Staff's recommended cost of AmerenCIPS' long-term debt, wherein Staff removed the incremental cost of AmerenCIPS' June 14, 2006 bonds. The parties are in agreement that in May 2005, AmerenUE transferred its Illinois utility assets to AmerenCIPS in exchange for a $67 million, five-year promissory note bearing a 4.7% interest rate. They also agree that on June 14, 2006, AmerenCIPS issued $61.5 million, 30-year bonds with a 6.7% interest rate, using the proceeds from that debt issuance to pre-pay the intercompany note held by AmerenUE. AIU had calculated a long-term debt cost for AmerenCIPS of 6.67%, whereas Staff calculates a long-term debt cost of 6.27% after removing the incremental cost of the June 14, 2006 refinancing.

The Commission notes that all parties agree with the general financial principle that as interest rates rise, the market value of outstanding fixed-interest rate debt falls such that the yield on that debt is competitive with that on new debt that pays interest at the new, higher interest rates. Both parties further agree that this is true due to the fact that the future stream of cash flows, both interest and principal, is less valuable when interest rates rise because the interest rate on the note is fixed.

a. AIU's Position

AIU submits that Ms. Phipps improperly removed from AmerenCIPS' embedded cost of long-term debt the incremental cost due to its decision to refinance the 4.70% intercompany note with 6.7% bonds. AIU takes the position that AmerenCIPS was justified in refinancing the 4.70% note, noting that the refinancing extended the date of final maturity from 2010 to 2036, while the original 4.70% note had a remaining life of just over three years. AIU submits that this extension reduced AmerenCIPS' refinancing risk and that the more permanent capital achieved by extending the term corresponded with the permanent T&D assets which it financed. In addition, AIU avers that the new structure relieved AmerenCIPS from having to fund annual amortization payments, and that the principal payments that remained at the time the note was refinanced were $5.6 million in May 2007, $5.9 million in May 2008, and $6.2 million in May 2009, which would have been made in addition to quarterly interest payments. AIU notes that the 6.70% bond has a non-amortizing bullet structure with full principal paid at maturity, pays interest semi-annually, and affords AmerenCIPS valuable flexibility through the extension of maturity and freedom from the burden of annual amortization payments.

While AIU agrees that an inverse relationship exists between interest rates and bonds prices, and that the value of a note or loan to the lender falls whenever interest rates rise, AIU submits that this principle is not relevant to a lender or an initial investor at loan origination. Further, early redemption terms are set at the note's inception and are typically not negotiated during the life of the loan, with the possible exception being a distress/bankruptcy situation.

AIU notes that the AmerenCIPS intercompany note states in part:

> . . . AmerenCIPS (the "Maker"), promises to pay to the order of Union Electric Company d/b/a AmerenUE (the "Payee")…the principal amount of $66,695,406…Upon receiving the prior written consent of the Payee, the Maker shall have the right to prepay the principal amount of this Note, in whole or in part, without premium or penalty. All partial prepayments shall be applied first to accrued interest under this Note and then to principal installments . . . . (AIU Initial Brief at 251)

AIU submits that the above excerpt states clearly the principal amount to be paid, and that any prepayment is without premium or penalty. AIU claims that there is no mention of a discount nor anything that can be construed as an ongoing negotiation between the parties regarding the amount ultimately owed.

AIU avers that Staff fails to distinguish the difference between the primary loan/bond market and the secondary market. AIU agrees that in an environment of increasing interest rates, the value of the AmerenCIPS note would decline, and were AmerenUE (the lender or investor) to attempt to sell the note to a third party in the secondary market, it would likely have had to accept a price below par to do so. AIU

submits that AmerenCIPS, as obligor, was bound by the contractual terms of the note that requires the payment of the full principal amount of the loan at or before maturity.

AIU notes that Staff argues that AmerenCIPS extended a benefit to AmerenUE by retiring a promissory note before its due date and that reflecting the full cost of the replacement note would violate Section 9-230 of the Act by increasing AmerenCIPS' cost of capital due to its affiliation with AmerenUE. Staff takes the position that when AmerenCIPS paid AmerenUE the entire balance to retire the note, it gave AmerenUE an unnecessary benefit and the resulting refinancing is unreasonable.

AIU submits however, that AmerenUE is not in the regular business of lending or financing third parties, but is instead a public utility in Missouri and was the lender here only because AmerenCIPS signed a promissory note when it acquired AmerenUE's Metro East properties. AIU contends that, unlike an institutional lender, AmerenUE would not be expected to take the money from the early retirement of the note and return to the debt markets to lend the money to another party at higher interest rates. AIU submits that there was no evidence that AmerenUE was dissatisfied with the interest rate under the note or that AmerenUE would have been willing to accept a discount to the principal for early payment. AIU posits that unlike the case of an institutional lender, there is no obvious opportunity cost to AmerenUE from remaining a party to the note. AIU submits that Staff's theory is inapplicable here, there is no violation of Section 9-230, and Staff's adjustment should be rejected.

b. Staff's Position

Staff witness Phipps calculated a 6.27% embedded cost of long-term debt for AmerenCIPS, while AIU proposed a 6.67% embedded cost of long-term debt for AmerenCIPS. Staff submits that the difference in those calculations results from Staff's adjustment to remove from AmerenCIPS' embedded cost of long-term debt the incremental cost due to AmerenCIPS' decision to refinance a 4.70% intercompany note with 6.7% senior secured notes. Staff avers that this adjustment is required by Section 9-230 of the Act, which 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 nonutility companies.

To assess whether interest rates had changed from the date the note was issued until one year later when AIU issued long-term bonds to replace the intercompany note, Ms. Phipps examined the 4.7% interest rates on the note in comparison to the implied interest rate for bonds with similar risk and terms to maturity. Ms. Phipps testified that on May 5, 2006, concurrent interest rates for 3-year and 5-year BBB+/Baa1 bonds indicate the implied yield on 4-year BBB+/Baa1 bonds equaled approximately 5.7% versus 4.7% on May 2, 2005, the date when AmerenCIPS issued the intercompany note. Staff further notes that although interest rates on 4-year bonds had risen since May 2005, AmerenCIPS did not receive any discount on the repurchase price of the promissory note. Staff asserts that due to this increase in interest rates, AmerenCIPS should have received a discount on the repurchase of the promissory note.

Relying on Section 9-230 of the Act, Staff removed from AmerenCIPS' embedded cost of long-term debt any incremental cost increase due to its decision to refinance the 4.7% intercompany note with 6.7% bonds because the loan agreement between AmerenCIPS and AmerenUE did not oblige AmerenCIPS to retire the promissory note at face value on the demand of AmerenUE, and in a transaction with an unaffiliated counterparty without such a provision, the borrowing entity would be able to redeem its indebtedness at a discount to face value.

Staff argues that because the value of a loan to the investor (i.e., lender) falls below face value whenever interest rates rise on loans with similar terms and risks. Staff says that in an arms length transaction, a borrower would not have to pay full principal amount to prepay a loan carrying a below market interest rate unless the original loan agreement required the borrower to do so. Staff submits that "make whole" provisions are designed to protect lenders' gains in market value in the event the borrower wants to refinance its debt should interest rates fall by requiring borrowers who want to refinance debt that bears above-market interest rates to pay in excess of the principal amount, not to protect their losses in market value whenever interest rates rise. Staff posits that the intercompany note did not include such a provision, and therefore, AmerenUE's principal amount was not protected from such a loss and it should not be granted after-the-fact.

Staff argues that AmerenCIPS' alleged inability to pay less than principal amount for below market rate debt is inconsistent with AmerenIP's experience. Staff notes that during January 2000, when long-term Baa-rated utility bond yields had risen to 8.40%, AmerenIP redeemed $32 million of its 7.50% first mortgage bonds maturing in 2025. Staff notes that AmerenIP's long-term debt schedule shows a gain was realized on that redemption due to higher long-term interest rates on the redemption date vis-à-vis the interest rate on the bonds.

To remove any incremental cost increase due to the refinancing, Ms. Phipps proposes two adjustments. First, she proposes dividing the balance of the 6.7% debt issuance in two components, with a 4.7% interest rate applied to the first component, which was the portion of the intercompany note that would have been outstanding as of June 30, 2007 had AmerenCIPS not retired it before maturity (i.e., $55,688,092). She then applies a 6.7% interest rate to the second component, which was the balance of the $61.5 million bonds (i.e., $5,811,908, which equals $61,500,000 less $55,688,092). She then proposes reducing the unamortized balances of debt discount and expense for the 6.7% bonds in proportion to the principal amount of those bonds that she included in AmerenCIPS' embedded cost of long-term debt. Next, she calculated the annual amortization expense for debt discount and expense relative to the prorated unamortized balance using straight-line amortization.

Staff notes that AIU opposes Staff's adjustment to remove the incremental increase in AmerenCIPS' cost of capital due to its intercompany note with AmerenUE and argues the refinancing benefited AmerenCIPS by extending the maturity from 2010

to 2036 and eliminating the obligation to fund $6 million annual amortization payments. Staff submits that AIU exaggerates the amount of flexibility gained by refinancing the intercompany note with bonds. Staff notes that not only did the original note include a provision that would allow AmerenCIPS and AmerenUE to extend the maturity of the note another five years by mutual agreement, but further, the note was subordinated to all other of AmerenCIPS' indebtedness. Staff avers that any benefits AmerenCIPS attributes to refinancing the note would have been benefits at the time of the asset transfer which originated the note. Staff submits that neither of AIU's arguments relating to the perceived benefits associated with refinancing the intercompany note are compelling.

Staff further suggests that neither of the arguments relating to the perceived benefits associated with refinancing the note are relevant. Staff insists that Section 9-230 of the Act does not allow the Commission to consider what portion of a utility's increased cost of capital caused by an affiliation is reasonable and therefore should be borne by ratepayers. According to Staff, the Second District Appellate Court in 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), 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."

Staff submits that consistent with Section 9-230 of the Act, it would be illegal to reflect any resulting incremental cost increase in AmerenCIPS' cost of capital, regardless of any potential benefits relating to repayment flexibility that AmerenCIPS may realize due to refinancing the intercompany note with bonds. Staff notes that AIU does not dispute that the refinancing increased AmerenCIPS' cost of capital, and Section 9-230 of the Act prohibits including in AmerenCIPS' cost of capital any increase that is the direct or indirect result of AmerenCIPS' affiliation with unregulated or non-utility companies.

While AIU suggests that the benefits justified refinancing AmerenCIPS' intercompany note from AmerenUE, Staff avers that it has never argued that AmerenCIPS should not have refinanced the note and Staff takes no position on that decision. Rather, Staff takes the position that AmerenCIPS paid an above-market cost to refinance the note.

While AIU claims that in the market, AmerenCIPS would never be able to prepay a note for less than the principal amount, Staff submits that this note did not contain language requiring redemption of the note for no less than the principal amount upon demand by AmerenUE. Staff avers that the note at issue in the instant proceeding makes redemption optional, and that under those circumstances, the borrower, in this case AmerenCIPS, should not redeem a note that carries a below-market interest rate by repaying 100% principal unless the note required the borrower do so.

While AIU argues that because the note was privately held, AmerenCIPS could not redeem it at a market rate below face value, Staff notes that AmerenCIPS chose to enter into a private loan agreement with an affiliate. Staff submits that had AmerenCIPS gone to the market to raise funds, rather than borrow from an affiliate, AmerenCIPS would have had the opportunity to repurchase outstanding, below-market rate indebtedness for less than face value. Staff posits that for ratemaking purposes, the Commission must treat the intercompany note as if it had been held by an unaffiliated party, and under this circumstance, AmerenCIPS would have had the opportunity to repurchase that indebtedness at market rates rather than face value.

Staff submits that its calculation of AmerenCIPS' embedded cost of long-term debt, which is consistent with the requirements of Section 9-230 of the Act, should be adopted and AIU's cost calculation should be rejected.

c. Commission Conclusion

The Commission notes that Staff is rightly concerned about the possibility of cross-affiliate subsidization and the possibility that AmerenCIPS' ratepayers are providing a windfall to AmerenUE by the redemption at issue here. The parties are in agreement that interest rates had risen since the note in question was issued. Staff argues that if AmerenCIPS made the business decision to refinance this note, it should have been able to redeem them for less than face value due to the interest rate environment. AmerenCIPS submits that this situation does not apply to bonds or notes unless they are in the secondary market, and suggests that ratepayers are benefitting by the restructuring of this debt as AmerenCIPS makes interest-only payments, and the term of this debt is now extended.

The Commission finds that while there may be some collateral benefits to AmerenCIPS' ratepayers, it appears that there is an increased cost due to this transaction, and pursuant to 9-230 of the Act, it would be improper to reflect any resulting incremental cost increase in AmerenCIPS' cost of capital, regardless of any potential benefits relating to repayment flexibility that AmerenCIPS may realize due to refinancing the intercompany note with bonds. The Commission finds that for purposes of this proceeding, Staff's calculation of AmerenCIPS' embedded cost of long-term debt, 6.27%, and its balance of long-term debt, $446,741,385, are reasonable and they are hereby approved.

D. Cost of Preferred Stock

Staff and AIU agree that the embedded cost of preferred stock for AmerenCILCO, AmerenCIPS and AmerenIP equals 5.34%, 5.13% and 5.01%, respectively. The Commission finds these embedded costs of preferred stock to be appropriate, and they will be adopted for the purposes of this Order.

E. Cost of Common Equity

1. Overview

a. Staff's Position

Staff witness Freetly estimates the investor-required rate of return on common equity to be 10.72% for the natural gas distribution operations and 10.68% for the electric delivery service operations of AIU. Ms. Freetly measured the investor-required rate of return on common equity with the discounted cash flow ("DCF") and Capital Asset Pricing Model ("CAPM") analyses. For the AIU gas utilities, she applied those models to a sample of gas distribution companies. For the AIU electric utilities, she applied those models to a sample of regulated electric utilities that are assigned industry classification codes of 4911 (electric services) or 4931 (electric and other services combined) within S&P's Utility Compustat. Specifically, she applied them to those utilities that have neither pending nor recently completed significant mergers, acquisitions or divestures; that have a long-term growth rate from Zacks Investment Research ("Zacks"); and whose beta was not affected by significant events. Ms. Freetly did not include Ameren Corporation in her Electric sample due to the proximity of an 18% decline in Ameren's stock price to a conference call during which Ameren management discussed the pending Illinois rate cases.

Staff notes that in order to determine the suitability of her cost of equity estimates for AIU's gas and electric utility operations, Ms. Freetly assessed the risk level of her gas and electric samples relative to that of each of the Illinois utilities. She calculated the funds from operations ("FFO") to interest coverage ratios and FFO to total debt ratios for the gas and electric samples and for the natural gas distribution and electric delivery service operations of each of the Illinois utilities. Staff submits that to estimate the risk of AIU going forward, Ms. Freetly compared the financial strength implicit in the revenue requirement Staff recommends for each of AIU's gas and electric operations to Moody's guidelines for electric utilities with medium business risk. Staff notes that although no formula exists for determining an assigned credit rating, Moody's provides broad guidelines for the ratio ranges that may be seen generally at different rating levels for regulated electric utilities. The FFO to interest coverage ratio equals interest divided into the sum of FFO and interest. The FFO to debt coverage ratio equals FFO divided by total debt. Each component was based on its contribution to Staff's recommended revenue requirement for AmerenCILCO, AmerenCIPS and AmerenIP.

Staff avers that for AIU's gas utility operations, the financial ratios implied by the capital component costs and capital structure are consistent with those of the gas sample, and therefore Ms. Freetly did not adjust the cost of common equity of the gas sample. Staff submits that the electric sample's FFO to interest coverage ratio of 4.0X and the FFO to total debt ratio of 18% fall within the guideline range for a Baa credit rating. Staff's revenue requirement recommendations, including the capital component costs, are indicative of a level of financial strength that is commensurate with an Aa3/A1 rating for Ameren CIPS and A1 ratings for AmerenCILCO and AmerenIP. Staff posits

that this comparison of financial ratios indicates that the electric sample has lower financial strength and therefore higher risk than AIU's electric delivery service operations. Staff notes that financial theory posits that investors require higher returns to accept greater exposure to risk, and that the investor-required rate of return is lower for investments with less exposure to risk. Staff submits that given the difference between the forward-looking financial ratios of AIU's electric delivery service operations and the financial ratios of the electric sample, the sample's average cost of common equity needs to be adjusted to determine the final estimate of AIU's costs of common equity for electric delivery service operations. Based on her analysis, Ms. Freetly adjusted the electric sample cost of equity downward 30 basis points, and submits that this 30 basis point adjustment for the electric operations of AmerenCILCO, AmerenCIPS and AmerenIP equals the spread between Baa1 and A1 rated 30-year utility debt yields as of February 13, 2008.

Staff submits that should the Commission accepts AIU's position to update the cost of long-term debt to reflect the recent refinancing of AmerenIP's auction rate bonds, Staff suggests that its updated cost of equity analysis should also be incorporated into the overall cost of capital calculation to obtain concurrent estimates of the costs of AIU's sources of capital. Staff's updated analysis, should the Commission accept AmerenIP's position on the auction rate bonds, indicates that the cost of equity is 10.73% for the natural gas distribution operations of AIU and 10.32% for the electric delivery service operations of AIU.

Staff notes that IIEC continues to recommend a return on common equity of 10.0% for both the electric and gas utility operations of AIU, while CUB recommends a return on equity of 8.955% for AIU gas distribution operations and 9.046% for the electric distribution operations.

b. AIU 's Position

AIU indicates in its Initial Brief that it has decided to accept, for the limited purposes of this proceeding, Staff's recommended cost of common equity. Accordingly, AIU has updated its recommended weighted cost of capital to reflect the acceptance of Staff's determination of the cost of common equity.

c. CUB's Position

CUB submits that it has introduced substantial financial literature which indicates that adhering to past Commission practices will result in an over-inflated return on equity. CUB avers that in order to achieve just and reasonable rates, the Commission should render a decision consistent with this new knowledge and the law and order a return on equity of 8.955% for AIU's gas distribution operations and 9.046% for its electric distribution operations.

CUB notes that a utility's required return on equity, or cost of equity, is the level of profit necessary to attract investment to a business with the utility's level of risk, and if

the cost of equity is reasonable and prudently incurred, it is a cost of doing business that utilities have a constitutionally protected opportunity to recover. CUB avers that the Act directs the Commission to ensure that the cost of equity used to develop rates fairly compensates investors for their risk, and assure that customers do not pay an excessive or unreasonable return in the utility's rates. CUB submits that these opposing responsibilities can be balanced fairly only when the Commission thoroughly considers the objective market factors that determine a fair return on investment. CUB avers that investors' required returns for investment in an enterprise of a given level of risk will change as the objective factors that define the equity markets change over time.

CUB notes that as this necessary cost of equity is not directly observable in the market for a particular utility, financial analysts have developed tools, such as the DCF model and CAPM, to estimate the cost of equity from observable market factors.

CUB notes that AIU initially recommended a return on equity of 11.00% for both its gas and electric operations, based on a DCF, CAPM, other risk premium analyses, and a comparable earnings test, but that AIU has now agreed to accept Staff's return on equity recommendations. CUB notes that Staff recommends a return on equity for AIU's electric distribution operations of 10.68%, and a 10.72% return on equity for AIU's gas distribution operations. CUB submits that Staff's recommendation is based on an average of widely divergent results from its DCF and CAPM analysis. CUB avers that Staff's approach is flawed as it ignores recent research on calculating cost of equity. CUB bases its recommendation on the results of a DCF model that incorporate the findings from the most current and advanced studies of financial markets. Based on the results of this model, CUB recommends an 8.955% return on equity for AIU's gas distribution operations and 9.046% return on equity for AIU's electric distribution operations. CUB submits that these represent the returns necessary to maintain AIU's access to equity capital markets on reasonable terms.

CUB submits that Mr. Thomas' calculation of rate of return on equity is based on significant financial research, is consistent with the law, and does not result in excessive rates to consumers. Therefore, CUB believes its recommended rate of equity, which is supported by substantial evidence presented in this docket, should be adopted.

d. IIEC's Position

IIEC witness Gorman recommends that the Commission award AIU a return on common equity of 10.0% for both the electric and gas utility operations of each of the AIU utilities. His recommendation is based on the results of his multi-stage DCF model, Risk Premium ("RP") model, and CAPM analyses. In part because the common equity shares of AIU are not publicly traded, Mr. Gorman's analyses applied the models to observable market information for groups of publicly traded utility companies that approximate AIU's investment risk. Mr. Gorman notes that proxy groups were also used by the other cost of equity witnesses in the case.

Mr. Gorman developed one proxy group himself to proxy AIU's investment risk for both gas and electric operations, while the other was the same proxy group used by AIU witness McShane in her cost of equity analyses. Mr. Gorman deemed both groups to have comparable investment risk to AIU, and that within that range of comparable risk, the Gorman proxy group was slightly more risky than AIU, while the McShane proxy group was slightly less risky. IIEC asserts that Mr. Gorman's analyses develop cost of equity estimates using higher and lower risk proxy groups that bracket the risk of AIU, and submits that the similarity of his results for the two groups reinforces the appropriateness of his estimates.

IIEC notes that as current economic circumstances can affect the suitability of particular cost of equity modeling techniques for developing cost of equity estimates, Mr. Gorman first investigated the market's current perception of the changing electric utility industry. Mr. Gorman testified that the market sees the industry in a capital spending cycle that is producing very strong growth in rate base, and in related earnings and dividends, which is providing a vehicle for strong growth over at least the next three to five years. IIEC submits that this transitional spending cycle has important implications for estimating a proper cost of common equity and explains Mr. Gorman's use of a multi-stage DCF model.

Mr. Gorman's analyses showed that a two-stage DCF model suggested a return on equity of 9.6%; Risk Premium Analysis, 10.0%, CAPM, 10.4%; and the midpoint-range of his analysis and his recommendation is 10.0%. IIEC submits that this proposed return on equity provides AIU with an opportunity to achieve cash flow credit metrics that will support an investment grade bond rating, allow AIU to maintain its financial integrity, and represents fair compensation for AIU's investment risk and will support AIU's access to credit markets on reasonable terms.

While IIEC recognizes that AIU has accepted Staff's recommended return on equity, IIEC notes that AIU continues to argue against Mr. Gorman's analysis. IIEC submits that its analysis is correct and that Mr. Gorman's recommended return is appropriate.

2. Annual Versus Quarterly DCF Model

a. Staff's Position

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. Staff avers that as a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that a stock price embodies. Staff notes that as the companies in Ms. Freetly’s gas and electric samples pay dividends quarterly, she applied a multi-stage, non-constant-growth quarterly DCF model.

Staff notes that Ms 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, while the third or “steady-state” growth rate is assumed to begin after the tenth year and continue into perpetuity.

Staff submits that for the first stage, Ms. Freetly used market-consensus expected growth rates published by Zacks as of February 14, 2008. 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, 5.15%. The growth rate Ms. Freetly employed in the intervening, five-year transitional stage equals the average of the Zacks growth rate and the steady-state growth rate. Staff avers that the growth rate estimates were combined with the closing stock prices and dividend data as of February 14, 2008, and based on these growth assumptions, stock price, and dividend data, Ms. Freetly’s DCF estimate of the cost of common equity was 9.41% for the gas sample and 10.01% for the electric sample.

While CUB claims that the Commission should use an annual DCF model because the quarterly adjustments to expected dividend yields result in doubly counting the effect of quarterly growth and thus, overcompensate shareholders at the expense of ratepayers, Staff submits that CUB witness Thomas has raised a working capital issue, not a cost of common equity issue. Staff submits that a working capital allowance compensates a utility for any delay between the time it expends cash to provide service and the time it receives cash from its customers for that service, and if a utility has authorized an appropriate working capital allowance, it will receive cash to pay for all costs of service as they come due. Staff avers that if an appropriate working capital allowance is authorized, CUB's argument is invalid because the working capital allowance will eliminate any surplus or deficit in earnings created by the timing of the utility’s cash collections and disbursements. Staff submits that because utility companies pay cash flows (i.e., dividends) over the course of a year and not all at the end of the year, use of a quarterly DCF model is not only appropriate for rate setting purposes, it is necessary for a utility to recover its true cost of common equity. Staff also notes that the Commission has explicitly rejected the use of an annual DCF model in previous proceedings. Staff argues that CUB's models variously ignore the time value of money, ignore the investor required return, and understate the cost of equity.

Staff submits that the argument regarding the use of a quarterly DCF versus an annual DCF model is a basic question of the time value of money, and note that CUB acknowledges the greater value of quarterly dividends relative to a single, annual dividend of the same total amount paid at the end of the year.

b. CUB's Position

CUB notes that DCF estimates the cost of equity capital by assuming that investors who purchase stock are paying a price that reflects the present value of the cash flows they expect to receive from the stock in the future, and DCF uses current

stock price and expected cash flows from dividends and earnings growth to estimate the return that investors expect to receive. CUB submits that investors' expectations of growth and cash flows are driven largely by historical experience, and that analysts are frequently overly optimistic.

In calculating the return on equity using DCF, CUB witness Thomas began with the same samples of comparable utilities used by AIU. Mr. Thomas removed eleven companies from the electric sample and one company from the gas sample as, in his opinion, their levels of historic growth were not sustainable. Mr. Thomas posits that inclusion of these companies introduces inappropriate bias into the sample.

CUB submits that it has introduced evidence that showed that the quarterly adjustments to expected dividend yield result in double counting the effect of quarterly growth and thus overcompensates shareholders at the expense of ratepayers. CUB avers that the use of any method that double-counts the effect of quarterly growth, and overcompensates investors at the expense of rate payers is inconsistent with the law and must be rejected.

CUB argues that this double-counting problem arises because investors, who receive their dividends quarterly, are able to reinvest their dividends and realize returns on those reinvestments. CUB submits that should the Commission authorize an adjustment to DCF to account for quarterly growth and compounding, the Commission increases the returns that it grants investors, while those investors are already earning more because of the timing of their dividend payments.

CUB posits that Staff and AIU inappropriately rely on outdated studies and findings from financial literature. CUB opines that Mr. Thomas relies on more recent and uncontroverted financial literature, which reveals the cost of equity should actually be much lower than Staff's estimates. CUB submits that recent studies have shown that CAPM contains a substantial bias, and is unreasonable to rely on to estimate a utility's cost of equity.

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3. Growth Rates

a. AIU's Position

AIU notes that IIEC witness Gorman's uses a two-stage DCF model that relies on two separate measures of investor growth expectations; the consensus of analysts' forecasts of earning growth for five years, followed by the consensus forecast by economists of long-term nominal growth in the economy as a proxy for the growth rate that utility investors expect into perpetuity. AIU submits that Mr. Gorman's two-stage DCF model represents a departure from his past practice, and notes that in prior proceedings before this Commission and other regulatory commissions prior to 2008, Mr. Gorman had relied solely on a single-stage constant growth DCF model. AIU posits that in this proceeding, Mr. Gorman has abandoned the constant growth model, on the grounds that the results are too high, because the analysts' forecasts of growth are too high to be sustainable.

AIU notes that this does not mean that Mr. Gorman is wrong for using a two-stage DCF model as one of his tests to estimate the cost of equity, as AIU witness McShane also used a two-stage DCF model as one of her five tests to estimate a fair return on equity for the AIU. AIU submits however, it is not reasonable to discard the results of the constant growth test, which is based on the more objective measure of investors' growth expectations than the two-stage model. AIU posits that a reasonable

approach would be to give equal weight to the results of the constant growth and two-stage models. AIU submits that the result of Mr. Gorman's constant growth DCF model, applied to his sample of electric utilities, is 11.66%, and giving equal weight to both the constant growth and two-stage model changes Mr. Gorman's DCF result to 10.6% (average of 9.6% and 11.7%).

AIU avers that Mr. Thomas recommends historic internal growth in the application of the DCF test, which AIU submits is not reasonable. AIU posits that the use of historical internal growth rates measured over a specific period, is a purely subjective choice on Mr. Thomas' part, with no objective link to investor expectations for the future that are embedded in current stock prices. AIU submits that Mr. Thomas' reliance on historic internal growth rates is logically inconsistent. AIU notes that the average achieved returns on equity over the 2002-2006 period that Mr. Thomas relied on were 12% for his gas sample and 11% for his electric sample, and according to the Value Line forecasts that Mr. Thomas provided, the samples are forecast to earn 11.9% and 11.7%, for gas and electric respectively, during 2010-2012.

While Mr. Thomas suggests investors are expecting utilities to earn only a 9.0% return on equity, AIU submits that Mr. Thomas fails to acknowledge that dividend payout ratios have declined for both his samples during the 2002-2006 period, and are expected to decline further. AIU notes the dividend payout ratio for Mr. Thomas' electric sample was 70% in 2002, but had declined to 61% by 2006, and are forecast to decline further to 57% in 2010-2012. AIU notes that failure to properly take this decline into account will result in an understatement in the "b x r" internal growth rate. In Mr. Thomas' electric utility sample, the average retention rate over the period 2002-2006 was 35%, while the forecast 2010-2012 retention rate is 43%. AIU argues that failure to recognize the higher retention rate would understate expected growth. AIU submits that by focusing on internal growth only, Mr. Thomas fails to consider any sustainable growth from external financing (the "SV" component of sustainable growth), and notes that failure to include the SV component can seriously understate the expected sustainable growth rate. This is particularly true during periods when utilities need to raise substantial amounts of capital to invest in infrastructure. AIU recommends the Commission reject Mr. Thomas' DCF method, and thus his recommended return on equity.

b. Staff's Position

Staff opines that CUB witness Thomas' position on the issue of growth rates is not clearly thought out. Staff notes that on one hand he argues that analyst growth rate forecasts should not be used exclusively, yet he ignores analyst growth rate forecasts when performing his DCF analysis and relies solely on a "b x r" growth rate estimate derived from historical data. Staff notes that this approach produces a growth rate of 4.21% for his electric sample, which is 39% lower than the lowest of his four analyst EPS growth rates (6.91%) and 52.5% lower than the highest of his four analyst EPS growth rates (8.86%) noted in his testimony. Staff submits that Mr. Thomas' "b x r" approach produces a growth rate of 4.69% for his gas sample. Staff suggests that if Mr.

Thomas had given weight to any of the analyst growth rates in his DCF analysis, the resulting costs of equity would have been higher than his recommendations of 8.955% for gas and 9.046% for electric.

While Mr. Thomas cites several studies in support of his conclusion and implies that those studies can be applied to utility growth rates, Staff avers that those studies do not support his position. Staff suggests that the studies he cites report generalized findings for all common stocks, and do not specifically suggest that growth rates for utilities are overstated relative to achieved growth. Staff notes in contrast, a study that indicates analyst growth rate estimates for utilities are not overstated.

Staff avers that the financial literature that Mr. Thomas cites study whether or not analysts' growth estimates are too high relative to achieved growth, as measured after the fact, and as such, they are ex post assessments of analyst growth rates' ability to accurately predict future growth, not assessments of analyst growth rates' value as estimates of investors' ex ante expectations. Staff notes that as investors' growth expectations are forecasts of the future, they may differ significantly from the ex post achieved growth. Staff submits that a cost of equity witness attempts to estimate investors' true growth expectations, irrespective of their accuracy as predictors of future growth. Staff posits that as long as analyst growth rates reflect investors' true growth expectations, use of analyst growth rates will accurately estimate the cost of equity, if properly applied in a correctly specified DCF model. Staff submits that Mr. Thomas incorrectly implies that analyst growth rates should be judged on their ability to accurately predict future growth, rather than on their value as proxies for investors' ex ante expectations.

Staff notes that Mr. Thomas argues that in circumstances where the dividend payout ratio is expected to change, use of the growth formula "b x r" to estimate expected future growth is superior to analysts' forecast. Staff notes that while Mr. Thomas indicates that Value Line's EPS and dividends per share ("DPS") growth expectations differ and neither correctly measures investor expectations, Staff notes that his solution rejects both and substitutes a growth rate that is almost a full percentage point less than either the EPS or DPS growth projection.

Staff submits that Mr. Thomas inappropriately extrapolates from a single source to suggest that investors, generally, are expecting dividend payout ratios to change. Staff notes that the difference between the Value Line dividend growth rates and earnings growth rates is not very large, and Staff submits that this does not indicate changes in dividend payout ratios beyond normal year-to-year fluctuations. Staff opines it is unrealistic to expect dividend payout ratios to remain absolutely constant in the near term. Staff further opines that Value Line's growth normalization technique for calculating forecasted growth rates is too mechanistic to ensure proper normalization. Staff submits that Value Line takes a simple three-year average of the base line data, such as EPS and DPS, to approximate the results of normal operations, however, if that three-year base is abnormally high, the growth rate indicated by the forecasted EPS or DPS will be lower than appropriate. Conversely, if that three-year base is abnormally

low, the growth rate indicated by forecasted EPS or DPS will be greater than appropriate.

Staff opines that even if one were to agree that the divergence of DPS and EPS growth disqualifies either for use in a DCF analysis, CUB's solution is inappropriate. Staff submits that when DPS grows more slowly than EPS, sustainable growth must be higher than DPS growth, not lower. Therefore, even if one assumes that the difference in the Value Line growth projections for DPS and EPS is sufficient for rejecting them both, which Staff disputes, the long-term steady state growth rate is higher than the DPS growth rate rather than lower as Mr. Thomas has estimated.

Staff notes that Mr. Thomas used historical dividend payout ratios and returns on equity to derive his b x r growth estimate, which he then added to the current dividend yield of each company in his samples to derive his cost of equity estimates. Staff avers it is inconsistent to apply a growth rate that reflects historical dividend payout ratios with dividend yields that reflect current dividend payout ratios for two reasons. Staff submits that growth rates derived from historical data are inconsistent with the prospective nature of the cost of common equity. Staff further notes that Value Line EPS and dividend per share growth data indicate that the average dividend payout ratio for his sample is expected to fall from 2004-2006 to 2010-2012. Staff posits this indicates that the retention ratios (i.e., retention ratio = 1 - dividend payout ratio) were lower during the period from which Mr. Thomas derived his b x r growth rate (2002-2006) than expected going forward, all else being equal. Conversely, it indicates that Value Line projects lower dividend payouts going forward, which would produce a lower dividend yield, all else equal. Staff submits that Mr. Thomas combines the lower retention growth rates from 2002-2006 with the lower current dividend yields, which understates the cost of equity.

Staff opines that numerous studies have shown that analyst growth rate estimates are the best proxy for investor expectations, and that analysts' forecasts are better predictors of actual growth rates than are predictors based solely on historical information. Staff submits the results of valuation models, such as the dividend growth model, are typically more accurate when the growth rate comes from analyst forecasts.

Staff notes that while CUB urges the Commission to adopt its estimates of sustainable growth using the internal growth method, claiming that academic literature concludes that historical growth rates are a far more accurate predictor of expected sustainable growth, Staff submits that the academic literature does not indicate that utility growth rates appear to be upwardly biased or demonstrate that analyst growth rates are poor proxies for investor growth expectations.

c. CUB's Position

CUB suggests the Commission adopt Mr. Thomas' method of computing growth rates, which estimates sustainable growth rate using the internal growth method. CUB submits that Mr. Thomas' analysis avoids reliance on analyst growth estimates and

takes into account changes in expected dividend payout ratios. CUB notes that it, Staff and IIEC agree that analysts' are currently producing overly optimistic growth forecasts that are unlikely to be sustainable over time. CUB submits however, while recognizing that analysts produce overly optimistic growth forecasts, Staff's and IIEC's subjective determination of how growth rates might change is inaccurate, and therefore, should be rejected in favor of the internal growth method.

CUB avers that the sustainable growth rate is a critical component of the DCF model, representing the amount of growth that investors expect to occur on their investment, and that is sustainable over the long-term. CUB submits that setting the growth rate component of the DCF model at an unreasonably high level would result in an estimate of the cost of equity that is also unreasonably high, all other things being equal.

CUB opines that historically, analysts have set their sustainable growth rate assumptions at unreasonably and unsustainably high levels. CUB asserts that to deal with this problem, Staff and IIEC have adjusted their approach to estimating the cost of equity by using non-constant and two-stage DCF models to account for the optimism of analysts' forecasts. CUB submits that these methods involve significant judgment and introduce a degree of uncertainty into the DCF analysis, which confirms that historical growth rates are a more accurate predictor of expected sustainable growth.

Mr. Thomas addresses both this analyst bias and the bias caused by expected changes in dividend payout ratios, by using the average historic internal growth rate for the sample companies to estimate the sustainable growth rate variable of DCF. CUB says when analysts are expecting the dividend payout ratio to change, their forecasts for both dividends and earnings will not accurately represent expected future growth in the DCF model. Currently, CUB claims analysts are expecting dividend payout ratios to change. Mr. Thomas' estimates of internal growth result in a growth rate of 4.21% for electric utilities and 4.69% for gas utilities. These estimates are considerably below analysts' expected 8.09% growth rate for electric utilities, and 5.20% growth rate for gas utilities. CUB submits that using analysts' growth expectations as the other parties suggest, will overstate the cost of equity.

CUB claims that while AIU argues against Mr. Thomas' use of historic internal growth in the DCF, CUB submits that AIU improperly relies on outmoded and unsupported theoretical arguments. While AIU argues that Mr. Thomas' use of historic internal growth is subjective and has no link to the investor expectations, CUB avers that AIU ignores the most current and relevant academic literature. CUB opines that the latest academic literature supports Mr. Thomas' conclusion that beyond two years, the best forecast of earnings growth is the historical average growth rate.

CUB also disputes AIU's argument that Mr. Thomas' reliance on historic internal growth rates is logically inconsistent. While AIU argues that there is an inconsistency because both past achieved returns on equity and Value Line forecasts of future returns are higher than Mr. Thomas' recommendation, CUB submits that this point actually

confirms Mr. Thomas' conclusion. CUB opines that the "Nagel Paper" makes clear historical average earned returns are unreliable as predictors of future returns.

Further, while AIU claims that Mr. Thomas fails to acknowledge that dividend payout ratios have declined, and are expected to decline further, Mr. Thomas' analysis acknowledges declining dividend payout ratios. CUB notes that because dividend growth is uncertain, the DCF formula uses only the current dividend payment (increased by the expected sustainable growth rate), instead of some analyst's estimated or forecasted dividend payment.

AIU further argues that by focusing on internal growth only, Mr. Thomas has failed to consider growth from external financing, which CUB submits is irrelevant. CUB notes that the internal growth method estimates the maximum level of growth that a company can sustain without injecting more capital into the business, which is consistent with the Commission's practice of granting regulated utilities a return on only their prudent and reasonably incurred investments. CUB submits that evaluating external growth is a highly subjective exercise which relies on questionable assumptions about the future and produces results that are inconsistent with the Commission's practice of granting rates that allow the companies to recover their costs during the test year, including pro forma adjustments.

CUB notes that Staff argues that a study by Chan, Karceski and Lakonishok (the "Chan" study) indicates that analyst growth rates for utilities are not overstated. CUB avers that the Chan study did not conclude that the studies Mr. Thomas relied upon were inaccurate, but instead found that low growth companies, such as utilities, did not behave the same as high growth companies. CUB submits that such a result is hardly surprising and does not undermine the finding that historic average growth rates are the best forecast of earnings growth. CUB avers that Mr. Thomas correctly relied upon studies that show analyst estimates beyond two years are inaccurate.

CUB asserts that it has shown that analysts' growth rates are poor proxies for investor growth expectations, and submits that the Commission must measure equity returns that reflect unbiased growth estimates, rather than upwardly biased analyst forecasts that diverge from the achieved growth rates. CUB avers that using analyst forecasts as estimates of growth will overstate the cost of capital estimate produced by the DCF.

CUB avers that Staff is incorrect when it argues that Mr. Thomas failed to acknowledge changes in the dividend payout ratio. CUB submits that as dividend growth is uncertain, DCF uses only the current dividend payment (increased by the expected sustainable growth rate), instead of analysts' estimated or forecasted dividend payment. As analysts' expectations of growth have been shown to be upwardly biased, CUB asserts that the best measure of growth is clearly the historic internal growth that companies in the sample group have actually experienced.

CUB notes that Staff contends that it is inconsistent to apply a growth rate that reflects historic dividend payout ratios with dividend yields that reflect current dividend payout ratios. While Staff argues that a historic perspective has value in forecasting the future, one can not reasonably forecast the future by looking solely to the past. CUB submits that beyond two years, the best forecast of earnings growth is the historic average growth rate. CUB avers that the studies Staff relies on are outdated and have been superseded by more current studies consistent with CUB's arguments.

d. IIEC's Position

IIEC notes that its witness, Mr. Gorman performed and assessed DCF analyses using both constant growth and multi-stage models. IIEC avers that Mr. Gorman rejected the constant growth model as, in his opinion, its results were based on growth rates that are not sustainable. IIEC opines that because of the current environment, Mr. Gorman and Staff witness Freetly both used multi-stage DCF models in developing their cost of equity recommendations.

IIEC notes that AIU witness McShane argues that Mr. Gorman's two-stage model assumes that investors only expect the forecast of growth to continue for precisely five years, with an immediate change thereafter to the long-term growth in the economy, which Ms. McShane avers creates inconsistencies in the DCF cost estimates for the individual companies. IIEC submits that this criticism demands a level of precision not otherwise required (or often seen) in the use of cost of equity models. IIEC avers that analysts regularly assume the validity of a single growth rate input -- in perpetuity -- in the exercise of their expert judgment. IIEC posits that Ms. McShane's criticism is not valid and should be rejected by the Commission.

IIEC submits that should the Commission accept Ms. McShane's criticism that the growth rate transition may not be as precise and immediate as her view of the two-stage model demands, then IIEC suggests at most ,Mr. Gorman's two-stage model uses a questionable expected growth input for a 1-3 year period of transition. IIEC notes that the Commission can only surmise at what point investors would expect the analyst's forecast growth rates to decline to levels that more closely track the growth in the economy. IIEC posits that underestimating the period over which the forecast growth rates are expected to prevail understates the cost of equity when the forecast growth rates exceed the long-term equilibrium growth rate and overstate the cost of equity when the converse is the case. IIEC submits that giving equal weight to the constant growth and two-stage DCF models is not a reasonable approach, under these circumstances.

While AIU contends that it is not reasonable for IIEC to discard the results of the constant growth test, IIEC notes that AIU admits that "the growth rates analysts are forecasting are not sustainable in the long-term," as is required for a constant growth DCF model. IIEC notes that Mr. Gorman's decision not to use a constant growth DCF model was the result of a detailed evaluation of the reliability of that model in the current environment. Mr. Gorman posits that near term analysts' growth estimates are too high

to be sustainable as long-term growth rates, similar to Staff's conclusion on this issue. Although AIU alleges that Mr. Gorman has changes his analyses from prior cases, IIEC submits that Mr. Gorman's consistent practice is to test analysts' growth rates to determine whether they are appropriate for use in a constant growth DCF model. Like Staff, Mr. Gorman found current market circumstances did not produce reliable and accurate results in a constant growth DCF model. IIEC submits that AIU presented no credible evidence that a constant growth DCF model using those analyst's near term growth rates that Mr. Gorman rejected would produce a reasonable return estimate. IIEC submits that Mr. Gorman's two stage DCF analysis is appropriate given current circumstances and should be adopted by the Commission.

4. CAPM 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. Toward that end, Staff witness Freetly used a one-factor risk premium model, the CAPM, to estimate the cost of common equity. Staff notes that in the CAPM, the risk factor is market risk, which can not be eliminated through portfolio diversification. IIEC and AIU also utilized the CAPM in there cost of equity analyses while CUB suggests there are significant problems with the CAPM.

a. CUB's Position

CUB submits that recent financial literature reveals CAPM contains a substantial bias, which renders it unreasonable to rely on to estimate a utilities cost of equity. CUB notes that a 2007 study it identifies as the "Nagel Paper," casts doubt on whether CAPM provides a better estimation of the cost of capital than a completely arbitrary model. CUB submits that the Nagel Paper is the most recent research available on forecast error in CAPM, and corroborates a long history of problems with CAPM.

CUB submits that the Nagel Paper compared a simplified version of CAPM to the mainstream version of CAPM, and five other well-known theoretical models, and concludes that forecast error caused by estimating factor loadings and expected risk premiums in the more complex models exceeds the precision gained by including the risk factors. CUB posits that despite this evidence that CAPM is inaccurate, Staff continues to recommend averaging CAPM results with DCF results to obtain a final recommendation for cost of equity.

CUB recommends that the Commission consider the evidence presented in this case and reject its previous method of averaging DCF and CAPM results to find a final return on equity recommendation. CUB recommends instead using a DCF calculation to estimate return on equity, and suggests the Commission adopt CUB's DCF result of 8.955% for AIU's gas distribution operations and 9.046% for AIU's electric distribution operations.

b. Staff's Position

Staff notes 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 betas from Value Line and a regression analysis to estimate the beta of the Gas and Electric samples. For the gas sample, her average Value Line beta estimate was 0.88, while her regression beta estimate was 0.74. For the electric sample, the average Value Line beta estimate was 0.83, while the regression beta estimate was 0.77. For the risk-free rate parameter, Ms. Freetly considered the 2.53% yield on four-week U.S. Treasury bills and the 4.72% yield on thirty-year U.S. Treasury bonds. Both estimates were measured as of February 14, 2008. Forecasts of long-term inflation and the real risk-free rate imply that the long-term risk-free rate is between 4.4% and 5.6%. Staff notes that following her analysis, Ms. Freetly concluded that the U.S. T-bond yield is currently the superior proxy for the long-term risk-free rate. 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 13.75% for the fourth quarter of 2007. Staff submits that after inputting those three parameters into the CAPM, Ms. Freetly calculated a cost of common equity estimate of 12.04% for the gas sample and 11.94% for the electric sample.

5. Beta

a. Staff's Position

Staff notes that CUB challenges Staff witness Freetly's beta. Staff claims that Ms. Freetly's methodology used to calculate the regression betas for her sample has been approved by the Commission in previous dockets. (Docket No. 02-0837, Order at 37-38; Docket Nos. 02-0798/03-0008/03-0009 (Cons.), Order at 85; Docket No. 00-0340, Order at 25; Docket No. 03-0403, Order at 42) The Order in AIU's last rate proceeding, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), states:

> As the Commission understands it, the Staff regression betas have been calculated in the same manner for several years and, with rare exception, have formed in part the basis for Commission approved returns on common equity. Just as the Commission routinely relies upon both the DCF and CAPM, the Commission believes it is reasonable to rely upon both Value Line and regression betas. (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at145)

While Staff notes that CUB witness Thomas claims that betas should not be adjusted for reversion to a market mean of 1.0, Staff submits that the Nagel Paper that he cites actually contradicts his argument and found that a CAPM using raw betas is less accurate in predicting realized rates of return and explicitly rejected use of an unadjusted beta. Staff posits that while the beta parameter is generally derived from

historical data, as in theory it should be a forward-looking number, Staff adjusted the raw (i.e., historical) betas for the sample companies to improve the accuracy of the beta estimates. Staff submits that the Armitage text Mr. Thomas cites with regard to this argument indicates that studies have shown that such adjustments result in appreciably better forecasts, finding that the reduction in both bias and inefficiency is greater the further away from one the beta in question is. Staff notes that Armitage states that the observed flatness of the Securities Market Line is due to two factors: 1) error in the estimation of true betas (i.e., the further above (or below) the mean an observed beta is, the more likely it is that the estimate error is positive (or negative)) and 2) regression toward the mean (i.e., moderation in risk over time).

While Mr. Thomas concludes that mean reversion for utilities with betas below 1.0 is wrong, citing a Gombola and Kahl article that suggests that utility betas actually revert to a utility average beta rather than a market mean beta of 1.0, Staff submits the derivation of the true industry mean beta is problematic. Staff avers that not only is any estimate of the true industry portfolio beta mean dubious, as betas change over time, but notes the farther below the market mean a raw beta is, the more likely its estimate error is to be negative. Staff posits that the average of a portfolio of low betas, each of which is likely to be biased downward, will, itself, likely be biased downward. Staff submits that Mr. Thomas' proposal to ignore beta reversion altogether and use an unadjusted beta was explicitly rejected in the Nagel Paper, and should be rejected by the Commission in this proceeding.

b. CUB's Position

CUB argued that the evidence presented in this case shows that CAPM is highly inaccurate, and suggested the Commission reject any rate of return that includes CAPM in the calculation. CUB submits that should the Commission use CAPM in setting the return on equity, the Commission should reject Staff's and IIEC's CAPM analyses as they use adjusted betas that result in even greater inaccuracies.

CUB notes that the beta parameter represents the degree to which the price of a stock moves with the overall market, and if the stock in question is less volatile (and hence, less risky) than the overall market, then its beta parameter will be less than 1.0, while if the stock is more volatile and risky than the overall market, then its beta parameter will be greater than 1.0. CUB submits that in the context of a CAPM analysis, an unreasonably high choice of beta parameter will result in an unreasonably high cost of equity.

CUB avers that while the Commission has historically relied on beta parameters that have been adjusted using the mean reversion adjustment, this adjustment is reasonable only under certain circumstances – when a company's beta can be expected to move toward 1.0 over time. CUB submits that utility stocks have not been shown to have beta parameters that move toward 1.0 over time, and argues that financial researchers have found that an underlying mean of 1.0 is too high for most utilities, and theorizing that utilities revert to a utility average beta.

While Staff attempts to refute this evidence by arguing that a portfolio of betas below 1.0 will be biased downward, CUB avers that Gambola and Kahl have already proven that the mean reversion adjustment methodology does not apply to utilities, and there is no basis with which to conclude that a portfolio of utility betas will somehow behave any differently than individual utility betas. CUB submits that the mean reversion adjustment incorrectly increases CAPM estimates of utility cost of equity, is inappropriate for use in a utility rate making proceeding, and should be rejected by the Commission.

c. IIEC's Position

IIEC posits that in recent years, electric utilities have implemented corporate strategies that have decreased their operating and financial risk factors. Specifically, they have pursued back-to-basics investment strategies that lower their operating risks, and they have divested non-regulated businesses to reduce debt and strengthen their balance sheets. IIEC submits that these trends are confirmed in the published observations of capital industry institutions like Value Line, which notes an increase in the common equity ratio and fixed charge coverage ratio of such utilities over the last three to five years, further lowering financial risk. IIEC avers that these risk reductions have resulted in robust stock return performance for electric utility stocks.

Mr. Gorman observed that over the last five to ten years, utility betas have exhibited an upward trend that is not associated with an actual increase in risk, rather, the apparent increase indicated by the high betas reflects that utility stocks have outperformed the market. Recognizing these market developments, Mr. Gorman employed a beta of 0.85 in his CAPM analysis, which IIEC submits is appropriate and should be adopted by the Commission.

6. Expected Risk Premium

a. AIU's Position

AIU submits that Mr. Gorman's CAPM takes an improper approach to estimating the market risk premium. AIU notes that he estimates the market risk premium in two ways. For one method, he adds the average historic real return on equities to the long-term forecast of inflation to arrive at an estimate of the future market return of 11.6%. From that estimated market return, he subtracts the forecast risk-free rate of 4.6% to arrive at an estimated market risk premium of 7.0%. His second approach takes the nominal historic return on equities from which he subtracts the historic achieved total return on government bonds (5.8%), arriving at a market risk premium of 6.5%.

AIU asserts that with respect to the first approach, adding the real return achieved on the market to expected inflation would be appropriate if there were any evidence that the expected return on the market moves in tandem with the rate of inflation, however AIU posits that there is no such evidence. AIU submits that in the

absence of any observable relationship between inflation and real returns, or any indication that there is any secular upward or downward trend in the nominal market returns, the nominal achieved market return is the better estimate of the forward looking market return. AIU notes that the nominal market return, as utilized in Mr. Gorman's second approach, is 12.3%, leading to a market risk premium over his 4.6% forecast risk-free rate of 7.7%.

AIU avers that Mr. Gorman's second approach to estimating the market risk premium entails subtracting the historic total return on government bonds (income return, capital appreciation return and investment return) from the total return on the equity market composite. AIU notes that the estimation of the market risk premium, requires the use of a proxy for the risk-free rate, and submits the total return achieved on government bonds is not the appropriate proxy for the risk-free rate, but instead the income return, not the total return, on bonds should be used as the proxy for the historical risk-free rate when estimating the expected market risk premium ("EMRP").

AIU posits that another consideration when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. AIU notes that the total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from a periodic cash flow, the capital appreciation return results from the price change of a bond over a specific period, while the reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. AIU submits that the income return is used in the estimation of the equity risk premium as it represents the truly riskless portion of the return.

While Mr. Gorman contends that using total returns on stocks while using income returns on bonds is a mismatch, AIU avers that this in not the case. AIU submits that it is appropriate to use income returns on bonds as the estimate of the ex ante expected risk-free rate while simultaneously using total returns on equities to estimate the expected return on the market. AIU argues there are no observable secular trends in the equity market returns that suggest the equity market returns are not a reasonable reflection of investor expectations, and there is no reason that the total returns on the equity market would not be used by investors to estimate the market risk premium relative to the risk-free rate.

AIU posits that the use of the income return of 5.2% instead of the total return on long-term Treasury bonds of 5.8% results in an equity risk premium of 7.1% (12.3%-5.2%), and the average of the two revised market risk premiums is approximately 7.4%, compared with Mr. Gorman's estimate of 6.75%. AIU submits this results in CAPM return on equity of 10.9% (4.6% + 0.85 X 7.4%), rather than Mr. Gorman's calculated 10.4%.

b. Staff's Position

Staff notes that IIEC witness Gorman relied on historical data to calculate two market risk premium estimates for his CAPM analysis. First, he estimated the expected return on the S&P 500 by adding an expected inflation rate of 2.3% to the 9.1% long-term historical arithmetic average real return on the market over the period 1926-2006. He then subtracted the projected yield on U.S. Treasury bonds of 4.6% to determine the 7.0% market premium. Second, he provided a historical estimate of the market risk premium by calculating the difference between the arithmetic average of the achieved total return on the S&P 500 of 12.3% and the total return on long-term Treasury bonds of 5.8% over the period 1926-2006, or 6.5%.

Staff submits that historical risk premiums do not adequately measure investors' current return requirements as historical risk premiums are based on realized returns. Staff avers that due to unpredictable economic, industry-related or company-specific events, the difference between realized and expected returns can be substantial. As such, Staff suggests the past relationship between two investments, such as common equity and debt, is unlikely to remain constant. Further, the magnitude of the historical risk premium depends upon the measurement period used. Staff suggests no proven method exists for determining the appropriate measurement period, and therefore historical 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.

Staff notes the Commission has consistently rejected use of historical data in determining the market risk premium in setting the investor-required rate of return on common equity, and submits the Commission should do so once again in this proceeding. In AIU's most recent rate proceeding, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), the Commission rejected Ms. McShane's estimate of the market risk premium and 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. (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 142-143)

Staff notes that Mr. Gorman claims Staff's market risk premium estimate is overstated due to Ms. Freetly's DCF derived return on the market, which he claims reflects a growth rate of 11.2%. Although Mr. Gorman presents market risk premiums over long historical periods as measured by Morningstar to indicate that Ms. Freetly's Market risk premium is inflated, Staff submits that historical market risk premiums do not

indicate the additional risk premium that common equity investors are expecting in today's market.

Staff suggests that while IIEC claims that the market risk premium presented by Staff is flawed and less reliable than Mr. Gorman's estimated market risk premium range, his calculation of Staff's growth rate does not factor in stock repurchases. Staff posits that Mr. Gorman's failure to consider stock repurchases in his calculation of growth produces an incorrect estimate of the growth rate implied in Staff's calculation of the market risk premium.

Staff avers that CUB witness Thomas presents academic research indicating that the proper expected common equity market risk premium for determining the investor-required rate of return is between 3 and 5%. Staff submits that the research cited represents various academics' opinions of the common equity risk premium investors should expect, not necessarily what the investors truly are expecting. Staff suggests that since the relationship between the returns of the stock market and U.S. Treasury bonds is not stable over time, current returns provide the best indication of what investors are expecting going forward, therefore Staff's estimate of the common equity risk premium, derived by subtracting the current yield on long-term U.S. Treasury bonds from the required return on the S&P 500 provides the actual difference between returns on risk-free and risky securities that exists in today's market.

Staff argues that its estimate of the market risk premium provides the actual difference between returns on risk-free and risky securities that exists in today's market, providing the best indication of what investors can expect going forward, and should be accepted by the Commission.

c. CUB's Position

CUB suggests that should the Commission continue to utilize CAPM in determining the return on equity, then it should adopt CUB's recommendation for the EMRP that will be used in CAPM. CUB notes the EMRP represents the expected return on a perfect portfolio of the entire market, in excess of the risk-free rate. CUB submits the EMRP should be the same for all markets and for all firms being examined in a CAPM analysis, as it is the beta factors, not the EMRP, that differentiate the return estimates for firms of varying risk.

Despite the fact that the EMRP should be the same for all markets and firms, CUB argues the other parties in the proceeding use biased analyst estimates of the EMRP using forecasted growth. CUB posits that the EMRP is a characteristic that is attributable to all investors and all potential investments, and therefore there is only one EMRP, 5.0%. CUB submits that Mr. Thomas relied on research from independent academics and investors to arrive at his conclusion that analyst-calculated EMRPs often contain significant upward bias. CUB submits that surveys of investors show that a reasonable estimate of the EMRP that investors expect is in the range of 3.0% to 5.0%.

CUB notes that Staff calculated EMRP using analysts' forecasted growth rates in a DCF analysis of companies making up the S&P 500, which forecasts CUB argues have their sustainable growth rate assumptions at unreasonably and unsustainably high levels. CUB submits the Commission should rely on the greater base of empirical data on which the published studies report and should the Commission use CAPM, use an EMRP of 5.0% in the CAPM.

CUB notes that while Staff argues that Mr. Thomas' EMRP estimate is inaccurate because the relationship between the returns of the stock market and U.S. Treasury bonds is not stable over time and thus current returns provide the best indication of what investors are expecting going forward, CUB submits EMRP is a characteristic attributable to all investors and applies to the full universe of all potential investments. CUB argues the Commission should not ignore available research that confirms that expectations of the EMRP are far below the level that Staff recommends and the EMRPs that have traditionally been approved by the Commission.

d. IIEC's Position

Mr. Gorman made two estimates of the market risk premium for use in his CAPM study. First, he relied on Morningstar data to estimate the actual historical achieved total return on the stock market versus the total return on long term Treasury bond investments. That analysis indicated a market risk premium of 6.5%. Mr. Gorman also used a risk premium study to estimate the forward-looking return on the market less his estimated risk-free rate to produce a market risk premium of 7.0%.

In support of his market risk premium estimates, Mr. Gorman cited actual market data compiled by Morningstar Ibbotson as support for a market risk premium in the range of 6.23% and 7.05%. IIEC avers that Ms. Freetly developed market risk premium estimates using a DCF derived return on the market, proxied by the S&P 500 less the risk-free rate, which produced a market risk premium estimate of 9.03%. IIEC notes that Ms. Freetly's DCF market return is based on a risk-free yield of 1.9% and growth rate of 11.2%. IIEC submits that the market risk premium estimation alternative presented by Ms. Freetly is flawed and less reliable than Mr. Gorman's as the growth rate estimate in her market based DCF return studies are too high to be used in a constant growth DCF study.

While Ms. Freetly's proposed alternative market risk premium is based on her DCF estimate of the market return, IIEC avers that her result reflects an implicit growth rate (over 11.5%) that simply is not reasonable. IIEC submits the sustainable growth rate for a utility can not plausibly be estimated to exceed the growth rate of the economy in which it operates. IIEC says that assuming growth rates twice the gross domestic product ("GDP") growth rate produces market risk premium results that exceed reasonable estimates like Mr. Gorman's.

Both Ms. Freetly and Ms. McShane challenge the historical market data cited by Mr. Gorman to support his contention that the market risk premium estimates they used

are excessive. Ms. McShane contends that the studies are not, in fact, adopted by Morningstar Ibbotson as the estimate of the market risk premium and, as a result, Mr. Gorman's estimate of the market risk premium should be on the order of 7.4%. IIEC submits that whether the Morningstar data were adopted is irrelevant, as Mr. Gorman did not use the data as mere plug-in inputs to his models. IIEC posits that the data represent actual investment returns that Morningstar collected, analyzed and published which Mr. Gorman relied on as this data is useful to investors in forming their expected returns. IIEC argues that Ms. McShane's argument is essentially that the data collected and published by a market institution was, in this instance, useless; which IIEC submits is not a credible argument.

IIEC notes that while Ms. Freetly criticizes any use of historical data to develop expectations for the future, including in expected risk premium analyses, IIEC submits that a CAPM analysis is, in fact, a risk premium analysis that estimates a beta factor from historical data. IIEC avers that Ms. Freetly relies on this risk premium study, including the beta derived from historical data, to support her recommended return for AIU in this case. IIEC argues that Ms. Freetly was unable to deny that her market premium determination is based on a DCF market return estimate that reflects an unsustainable growth rate more than twice the expected long-term growth rate of the national GDP. IIEC posits that her forward-looking market DCF return is inflated and unreliable, which in turn makes her CAPM market risk premium unreliable and flawed. IIEC avers that if Ms. Freetly's CAPM is corrected to reflect a reasonable market risk premium, her analysis also would support a return on equity of less than 10.0%.

IIEC notes that AIU takes issue with Mr. Gorman’s EMRP estimate used in his CAPM analysis, arguing that the total return achieved on government bonds should not be used as the appropriate proxy for the risk-free rate. IIEC posits that for bonds held to maturity; which IIEC argues is a precondition to long-term yields; the subsidiary return components on which AIU focuses are not a factor. IIEC notes that capital appreciation and reinvestment income, which AIU argues are not risk free, are realized only if the bond is not held to maturity, and they disappear when the bond fully matures.

While AIU also takes issue with Mr. Gorman’s reliance on the historical real return on the market combined with a forward-looking inflation expectation to estimate EMRP, arguing it would be more appropriate to use the nominal actual achieved return on the market (12.3%), IIEC asserts it is more appropriate to create a forward-looking expected return on the market as Mr. Gorman did. IIEC notes that the nominal return on the market Ms. McShane uses reflects historical inflation, while Mr. Gorman's forward-looking expected return on the market reflects forward-looking inflation outlooks and is incorporated in the market's current valuation of securities.

IIEC claims that while Mr. Gorman’s method of estimating an expected return on the market does rely on historical data and forward-looking market expectations, this is a widely accepted methodology. IIEC submits that Ms. McShane and Ms. Freetly, in their own CAPM studies, relied on historical data adjusted for forward looking expectations, using Value Line betas and betas calculated using historical stock prices.

IIEC avers that in each case, the beta is estimated from a regression of historical data on stock price variability in relationship to the market price variability, then adjusted to reflect forward-looking risk expectations.

While AIU argues that Mr. Gorman's market risk premium is inconsistent with the historical data and analysis both analysts used, IIEC notes that for her comparison to Mr. Gorman, Ms. McShane relied exclusively on the highest estimated return from the data and a market risk premium of 7.1% while Mr. Gorman used data from Morningstar. IIEC avers that Morningstar indicates that an EMRP reflecting sustainable valuation results can range from 6.2% to 7.1%, depending on the market index used. IIEC submits there is no basis for AIU's argument that only Morningstar's highest market risk premium estimate should be used to estimate AIU's return on equity in this proceeding. IIEC avers that these same arguments apply to Staff's criticism of Mr. Gorman's analysis.

7. Risk Premium Model

a. AIU's Position

AIU notes that IIEC witness Gorman estimates the equity risk premium by averaging the results of two approaches. In the first, the differentials between the regulatory commission authorized rates of return on equity and the yields on long-term U.S. Treasury bonds for the period 1986-June 2007 are determined. Using the 5.2% mid-point of a range of differences of 4.4% to 5.9% (in which 18 of his 22 observations fall), he adds his forecast 30-year Treasury bond yield of 4.6% to arrive at a return on equity of 9.8%. Mr. Gorman's second risk premium approach adds a utility risk premium over utility bonds of 3.7% (mid-point of a range of 3.0% to 4.4%) to the 13-week average yield on Baa rated utility bonds for the period ending February 22, 2008 of 6.5%, producing a cost of equity of 10.2%. The two models are given equal weight, for a return on equity of 10.0%.

AIU submits that Mr. Gorman has incorrectly estimated the risk premium. AIU posits that using regulatory commission authorized returns as the point of departure does not constitute an independent test of the required return on equity; and even assuming that the allowed returns equate to the cost of equity, it is inappropriate to simply average the results for the entire period 1986-June 2007. AIU avers that this approach fails to recognize that there is an inverse relationship between interest rates and equity risk premiums, and use of this approach understates the required risk premiums in the current and forecast interest rate environment.

AIU notes that the required risk premium at Mr. Gorman's forecast long-term Treasury bond yield of 4.6% was estimated from Mr. Gorman's data through a simple regression analysis using the indicated historic bond yields as the independent variable and the corresponding risk premiums (allowed return on equity minus the bond yield) as the dependent variable. AIU posits that the results indicate that the equity risk premium implicit in the regulatory authorized returns on equity increases (decreases) by 39 basis

points for every one percentage point decrease (increase) in the long-term Treasury bond yield.

AIU submits that based on the relationship described above, the equity risk premium and the indicated return on equity at Mr. Gorman's forecast long-term Treasury bond yield of 4.6% is as follows: the indicated risk premium is 5.8% and the indicated return on equity is 10.4%, compared to Mr. Gorman's result of 9.8% calculated using simple average risk premiums.

AIU avers that this same problem exists with Mr. Gorman's risk premium over utility bond yields. At Mr. Gorman's 6.5% utility bond yield, the indicated risk premium is 4.2%, rather than the 3.7% he relied on, for a return on equity of 10.7%, an increase of 0.5% from his reported result of 10.2%.

AIU notes that Mr. Gorman's risk premium test estimate is the simple average of the results of the risk premium over Treasury bond yields and the risk premium over utility bond yields models, and the average of the two revised versions of the models is 10.6% (compared to Mr. Gorman's 10.0%).

b. IIEC Position

In his development of Risk Premium cost of equity estimates, Mr. Gorman used two distinct estimates of the market risk premium to define the range of that factor. The first estimate was based on the difference between the commission authorized returns on common equity and Treasury bond yields, the second on the difference between commission authorized returns on common equity and contemporary A-rated utility bond yields. Mr. Gorman's risk premium analyses produce a return estimate in the range of 9.8% to 10.2%, with a midpoint estimate of 10.0%.

Mr. Gorman avers that his estimated range for the utility equity risk premium is consistent with risk premiums actually found appropriate over a period of almost three decades, adjusted as indicated by prevailing utility bond to Treasury bond spreads. Mr. Gorman asserts that his use of a range of utility equity risk premium estimates, as opposed to a spot estimate, best takes into account the unpredictable variance in the risk premium stemming from changes in investor perception and market conditions.

IIEC posits that while Ms. McShane argues that an inverse relationship between bond prices, inflation and corresponding equity investments needs to be recognized in IIEC's risk premium analysis, IIEC does not agree. While Ms. McShane argues that current lower interest rates mean that the risk premium from Mr. Gorman's analysis should be increased, IIEC suggests this is a simplistic correction for a relationship that is neither simple nor unchanging.

As Ms. McShane recognizes, Mr. Gorman's risk premium test covers a period which has been characterized by both high and low inflation. IIEC submits that his study directly takes account of the unpredictable variances in actual movements of

interest rates as well as equity returns, and as it covers a long period, his analysis avoids giving undue influence to possibly anomalous periods. IIEC notes this smoothing effect is supplemented by Mr. Gorman's consideration of current indicators, which gives emphasis to periods that may have more investor influence, as Ms. McShane states is appropriate.

With respect to Mr. Gorman's Risk Premium cost of equity estimate, AIU argues that Mr. Gorman "fails to recognize that there is an inverse relationship between interest rates and equity risk premiums" and that he "thus understates the required risk premiums in the current and forecast interest rate environment." IIEC says AIU witness McShane based this conclusion on her regression analysis using historic bond yields as the independent variable and the corresponding risk premiums (allowed return on equity minus the bond yield) as the dependent variable. IIEC claims the relationship between interest rates and equity risk premiums is not constant, may be positive or negative, and can not be predicted with certainty. Consequently, analyses like Ms. McShane's are sensitive to the period from which data are taken. Despite the academic research showing a changeable interest rate/risk premium relationship, IIEC claims AIU has provided no evidence that the alleged inverse relationship actually exists today. IIEC submits that the most important attribute of the alleged relationship, for AIU, is that it increases the risk premium and inflates the return on equity estimate.

IIEC submits that Mr. Gorman's equity risk premium was derived from data that avoids the unpredictability of the interest rate/equity risk premium relationship. Using Treasury/utility bond yield spreads to track contemporaneous investment risk differences between equity securities and debt securities, Mr. Gorman used this analysis to gauge whether the equity risk premium used in this case should be at, above, or below the average historical level. IIEC notes that Mr. Gorman's analysis was based on a measure of investors' market risk assessments, and not on an inference of investors' assessments, from the unreliable inverse relationship with interest rates.

8. Adjustment for Reduced Risk of Gas Operations

a. AIU's Position

AIU notes that IIEC recommends a downward adjustment to its recommended return on equity of at least 0.50% if the riders proposed by the AIU are adopted by the Commission. AIU submits that this recommendation is purely speculative and Mr. Gorman has provided no indication of whether other utilities in his sample might already have access to similar riders. AIU submits that the proposed QIP rider is to the benefit of customers, not only because it will result in required infrastructure, but because it will reduce the regulatory costs and burden of serial rate proceedings that might otherwise be required, and therefore Mr. Gorman's downward adjustment should be rejected.

AIU also disagrees with CUB's recommendation to reduce the return on equity by 67.5 basis points if the VBA rider is approved for the gas distribution operations. AIU posits that CAPM, to which the Commission has traditionally given significant weight,

does not provide investors compensation for weather risk, and provides compensation for non-diversifiable risk only. AIU submits that weather is a diversifiable (company-specific) risk. AIU claims that seven of the eight gas distribution utilities in Ms. McShane's sample have partial or full weather protection, thus, any risk-reducing impact of the weather protection on the required return on equity is already reflected in DCF cost of equity estimates.

AIU notes the CUB witness Thomas attempts to place a value on the AIU gas distribution operations' associated with proposed Rider VBA by "backcasting" the increase in return on equity that the utilities would have experienced between 2002/2003 (prior test years), and 2006, had Rider VBA been operational. AIU notes that Mr. Thomas estimates that with Rider VBA, the actual returns on equity would have been on average 221 basis points higher. As Mr. Thomas notes that the earlier test years were based on 30-year normal weather, while AIU is proposing rates now be set on 10-year normal weather, he attempts to adjust the 221 basis points for the proposed change in weather normalization methodology. AIU avers that Mr. Thomas calculated that AIU's estimated reduction in the variance of heating degree days from normal that is expected to result from switching from 30-year to 10-year normal weather will translate into a similar reduction in the impact that Rider VBA would have on return on equity. AIU submits that Mr. Thomas then reduced the 221 basis point impact to 142 basis points. To account for other factors, AIU notes that Mr. Thomas recommends that the allowed return on equity be reduced by 67.5 basis points.

Mr. Thomas' analysis of the impact on return on equity from moving from 30-year to 10-year normal weather assumes that the 35.85% decline in heating degree day deviations translates into an identical percent reduction in the impact of the Rider VBA on return on equity. AIU submits that Mr. Thomas fails to recognize the reduction in the average customer usage that moving to 10-year normal weather would have produced, which AIU claims would have changed the delivery rates required to recover the revenue requirements established for the 2002/2003 test years.

AIU submits that the following table summarizes the average customer usage reflected in the development of residential rates for the 2002/2003 test years compared to the proposed average customer usage based on the 2006 test year.

Company	2002/2003	2006
AmerenCILCO	946	823
AmerenCIPS	899	767
AmerenIP	904	779

While some of the change would have been due to ongoing conservation, AIU submits the majority of the reduction is due to the switch from 30-year to 10-year normal weather. AIU asserts that if the average customer usage proposed in this proceeding had been used to set the delivery rates required to recover the 2002/2003 revenue requirement, the outcome of Mr. Thomas' analysis would have been significantly

different. Ms. McShane compared Mr. Thomas' estimates of the impact of Rider VBA on return on equity from the residential classes only to the impact that would have resulted had 2002/2003 delivery rates been set using 2006 test year average customer usage. While Mr. Thomas' analysis produced an average increase in return on equity of 147 basis points had Rider VBA been applied only to the residential rate class, AIU posits that the replacement of the 2002/03 average customer usage with the 2006 test year average customer usage shows that the average return on equity would have decreased by 64 basis points. This suggests to AIU that it would have refunded money to customers, rather than recovering money from customers. AIU submits that while there would have been some decline in average customer usage from conservation since 2002/2003, the impact of Rider VBA would have been negligible.

AIU avers that while Mr. Thomas makes the assumption that the reduction in the differential between the allowed and actual return on equity due to the operation of Rider VBA translates into a similar reduction in required return on equity, his assumption has no theoretical or empirical basis. AIU notes Ms. McShane's analysis suggests that AIU would have owed customers money if Rider VBA had been in place, while following Mr. Thomas' logic, the cost of equity should increase, which AIU submits does not make sense.

b. Staff's Position

Staff notes that Ms. Freetly did not incorporate the lower risk associated with the Rider VBA revenue decoupling mechanism that AIU proposes in her cost of equity recommendation for the natural gas distribution operations of AIU. Staff submits Rider VBA would effectively separate the gas utility's fixed cost recovery from the amount of gas that it sells, which would result in actual utility revenues that more closely track its projected revenue requirements and should not change with increases or decreases in sales. Staff avers this would give AIU greater assurance that the authorized rate of return will be earned. Staff notes that Moody's states that rate designs that compensate the gas utility for margin losses caused by conservation and weather-related variations in gas consumption stabilize the utility's credit metrics and credit ratings. Staff submits that as the use of a gas decoupling mechanism would reduce risk to a gas utility, a downward adjustment to the rate of return on common equity is appropriate to recognize the reduction in risk associated with the use of a decoupling mechanism.

Staff avers that Moody's analysis of gas utilities focuses on four core rating factors: sustainable profitability, regulatory support, ring fencing, and financial strength and flexibility. Staff submits that among the risk factors reflected in return on equity is the utility's ability to increase earnings despite customer gas conservation, and adoption of a gas decoupling mechanism in a utility's rate design would lower the risk of the utility not achieving the authorized return on equity. Moody's assigns the return on equity factor a 15% weight in determining the overall credit rating score.

Regulatory support considers the strength of the utility's relationship with the regulatory commission. Staff avers that Moody's states that the ability of the utility to

recover allowed expenses in a timely manner and its ability to earn its authorized rate of return is a very important component of the utility/regulator relationship. Staff posits a utility's score on this factor would be improved with approval of a gas decoupling mechanism since its ability to earn its authorized rate of return would be enhanced. Moody's assigns a 10% weight to the regulatory support factor when determining the overall credit rating score.

Staff notes that although Moody's does not identify the precise impact that revenue decoupling would have on these two factors, enhancing the utility's ability to earn its authorized rate of return would be viewed favorably and could increase the scores assigned to the return on equity and regulatory support factors. Hence, Ms. Freetly assumed that the credit ratings assigned to each of these factors would improve by one credit rating. Since these two factors comprise 25% of the overall weighting, raising the scores for these two factors by one rating would result in a one notch increase in the overall credit rating (i.e., 25% x 3 = .75 rounded to 1). Consequently, if the rating assigned to the return on equity and regulatory support factors is raised by one rating, the overall credit rating for the utility would advance by almost one notch. Staff argues that if the overall credit rating for a company is Baa1 before revenue decoupling, it would most likely improve to A3 with commission approval of a decoupling mechanism. Staff notes the average Moody's credit rating for Staff's gas sample is Baa1, and the spread between utility bonds rated Baa1 and A3 is 10 basis points. Therefore, Staff recommends that the return on common equity for the gas operations of AmerenCILCO, AmerenCIPS and AmerenIP be reduced 10 basis points should the Commission approve Rider VBA to recognize the reduction in risk associated with the use of a gas decoupling mechanism. In the event the Commission approves Rider VBA, the referenced cost of equity adjustment will necessarily result in a reduction to Staff's cost of equity recommendations for the gas operations of AmerenCILCO, AmerenCIPS and AmerenIP.

Staff asserts that Rider QIP would also affect the risks and costs of capital of AIU. First, Staff explains, Rider QIP would effectively create two classes of assets from a risk perspective: rate base and Rider QIP assets. Since the riskiness of those two classes of assets could be very different, Staff recommends that the Commission authorize a different rate of return for Rider QIP assets than it authorizes for rate base. Staff does not believe that Rider QIP assets would affect the risk of rate base assets; therefore, Staff does not recommend any adjustment to the authorized rate of return on rate base should the Commission approve Rider QIP.

According to Staff, Rider QIP's affect on AIU's risk (and thus the costs of capital) is a function of how it would operate. Staff is proposing modifications to Rider QIP in the event the Commission approves such an infrastructure rider. Nevertheless, Ms. Freetly addresses how certain elements of the rider would affect risk. Staff maintains that a downward adjustment to the costs of common equity would be appropriate for each Rider QIP component the Commission adopts that would reduce risk, while an upward adjustment to the costs of common equity would be appropriate for each Rider QIP component the Commission adopts that would increase risk.

Staff notes that in comparison to rate base cost recovery, the recovery of the capital costs of projects run through Rider QIP would be more timely. All else equal, Staff states that this reduction in regulatory lag reduces the risk of Rider QIP projects. Should Rider QIP be approved, Staff is further proposing that the rider include a true-up, which Staff submits would increase the probability that the utility will recover all Rider QIP costs, including a return on the capitalized costs, relative to rate base costs. Staff contends that this increased certainty of more timely cost recovery would decrease the risk of Rider QIP projects. Staff submits that nothing in Rider QIP would require AIU to share operating cost savings with customers, which would also reduce the risk of Rider QIP. Staff however is also proposing that the QIP rate be capped so that recovery of the QIP adjustment is discontinued if the utility is earning above the authorized rate of return, which feature would increase the risk of Rider QIP projects because it effectively constrains upside earnings variability of rate base.

Staff indicates that the risk implications of the four Rider QIP components discussed above are cumulative. Therefore, should the Commission: (1) adopt Rider QIP, (2) include a true-up mechanism, (3) not include a pass-through of operating cost savings, and (4) include an earnings cap, Staff contends that four separate adjustments to the Rider QIP cost of common equity would be appropriate. Staff states that the first three adjustments should each reduce the Rider QIP cost of common equity, while the last adjustment should increase the Rider QIP cost of common equity. Staff does not recommend specific cost of common equity adjustments, although Staff agrees that Rider QIP projects would be less risky than projects whose costs are not recovered through a rider, the record contains no analysis-backed quantification of that risk reduction and its effect on cost of capital.

c. CUB's Position

CUB notes that AIU proposes several new riders as part of its filing, and while CUB urges that both Riders VBA and QIP be rejected by the Commission, should the Commission allow either Rider, the Commission should recognize that these riders have an effect on the riskiness of AIU that must be reflected in rates. CUB says that if the Commission chooses to approve Rider VBA, the Commission should reduce AIU's cost of equity by 67.5 basis points. If the Commission approves Rider QIP for AIU's electric operations, CUB argues the Commission should allow AIU to recover only its embedded cost of long-term debt on projects financed under this rider to adjust for the reduced risk AIU has when making such investments.

CUB opines that Rider VBA was proposed to protect AIU and its investors from deviations in monthly sales due to fluctuations in normal weather conditions and reduced customer demand, thereby reducing the risk that AIU will realize revenues below its approved revenue requirements. CUB submits this rider also minimizes shareholder risk due to future reductions in customer demand caused by weather and declining per customer usage, and would also reduce overall operating risk that arises

from regulatory lag. CUB argues that these changes are designed only to benefit shareholders, and are simply not necessary to assure AIU's financial stability.

CUB submits the benefits of Rider VBA accrue directly to AIU's common equity shareholders, as Rider VBA would provide revenue stability, and enable AIU to increase earnings in the future. CUB submits that the evidence demonstrates that the impact of VBA during 2003 and 2006 would have been to increase the total AIU gas operation return on equity by between 16 and 385 basis points, with an average impact of 221 basis points. CUB submits that the value of Rider VBA to AIU's shareholders is much greater than the arbitrary 10 basis points reduction the Commission granted to Peoples for a similar rider. Should the Commission approved Rider VBA, CUB suggests AIU's return on equity should be reduced by 67.5 basis points, which CUB submits is less than half of the impact of Rider VBA, and is less than the impact that weather normalization alone is likely to have on variability in AIU's return on equity.

CUB notes that while AIU argues against Mr. Thomas' recommendation to reduce its gas distribution return on equity by 67.5 basis points for Rider VBA, CUB posits that AIU inadvertently supports Mr. Thomas' argument that the CAPM is an unreliable model, when it argues that in principle, CAPM does not evaluate weather risk. CUB posits that Rider VBA will produce more stable and certain cash flows that will translate into increased confidence that investors will receive their required return, however, this decreased riskiness is not captured directly in CAPM framework. CUB submits that CAPM's failure to evaluate this significant driver of investor returns substantiates Mr. Thomas' conclusion about the limited worth of the model.

CUB notes that AIU also argues that, because seven of the eight gas distribution utilities in its witness' sample have partial or full weather protection, any risk-reducing impact of the weather protection on the required return on equity is already reflected in the DCF cost of equity estimates. CUB submits that the Commission rejected a similar argument in the recent Peoples rate case, Docket Nos. 07-0241, 07-0242 (Cons.).

CUB avers that AIU argues that Mr. Thomas' quantitative analysis of the impact of Rider VBA is inaccurate, failing to recognize the reduction in the average customer usage that moving to 10-year normal weather would have produced. AIU argues that had Rider VBA and 10-year weather normalization both been in place for the residential class during 2002/2003, Rider VBA would have resulted in rate credits rather than surcharges. CUB notes however, that AIU witness Laderoute's schedule 14.3 shows there has been a marked decline in the 10 year moving average of heating degree day data for central Illinois since the late 1990's. CUB submits that using 10-year weather normal in 2002 would have resulted in per customer usage higher than AIU has proposed in the 2006 test year. CUB avers that to assume that the lower 2006 usage levels approximate normal in 2003 makes little logical sense, and renders Ms. McShane's analysis useless to the Commission. CUB notes that in addition, Ms. McShane's analysis ignores the impact that Rider VBA would have on the small commercial class, a feature which is necessary to compare the two analyses, nor does she analyze the rising price of gas and its effect on consumption.

CUB also disagrees with AIU's position that there is no connection between the reduction in the differential between the allowed and actual return on equity due to the operation of Rider VBA and the returns earned by investors. CUB submits the benefits of Rider VBA accrue directly to AIU's common equity shareholder as equity holders are exposed to more cash flow risk than debt holders because public utility debt holders are paid first out of a company's earnings, while any remaining earnings then accrue to shareholders through growth from retained earnings and cash flows from dividends. Because Rider VBA provides revenue stability, and will enable AIU to increase earnings in the future, the value of this stability accrues directly to equity shareholders, CUB submits this should be accounted for by reducing AIU's return on equity.

CUB notes that AIU has also proposed Rider QIP for its electric operations. CUB submits that should Rider QIP be adopted, AIU will face significantly reduced risk when investing capital in the plant accounts covered under Rider QIP because the rider guarantees cost recovery, which protects investors from the possibility that they will fail to recover their investment. CUB posits the Commission must properly account for this significantly reduced risk in setting AIU's cost of capital. CUB submits that if Rider QIP is approved, AIU should receive a cost of capital on any investment made under Rider QIP that is equivalent to each utility's embedded cost of long-term debt, which AIU has proposed is 6.668% for AmerenCILCO, 6.538% for AmerenCIPS, and 7.975% for AmerenIP. CUB submits this return will allow AIU access to the capital it needs to finance projects under QIP, while recognizing the dramatically reduced risk. CUB believes this recommendation to limit the cost of capital on Rider QIP investments is conservative and the Commission may find that other, additional measures are necessary.

d. IIEC's Position

IIEC notes that AIU is proposing riders that would effectively change the rates set in this proceeding to assure levels of revenues that fully recover, or IIEC suggests possibly exceed, its cost of service. IIEC claims the proposed riders can actually provide AIU with an opportunity to earn more than its authorized return on equity. IIEC submits that rate adjustments, pursuant to the proposed riders, are not based on consideration of all of AIU's revenues, expenses and invested capital, but on only selected elements. IIEC suggests that if the Commission approves the requested riders, then AIU's risk would be reduced, and a reduction to its authorized return on equity would be warranted.

IIEC avers that if either of the proposed Riders if approved, the risk of AIU not recovering its authorized targeted revenues would be shifted to customers (in the form of increased rate volatility), AIU would gain revenue stability, and the market would perceive AIU as a firm with reduced risk. IIEC notes the parties examining the cost of equity effect of the riders do not disagree that approval of one or both riders will have such an effect, however they do disagree on the magnitude of the necessary adjustment to their recommended costs of equity. Mr. Gorman recommends that AIU's

recommended return be decreased by an amount in the range of at least 0.5% with rider approval, which would make IIEC's recommended return on equity 9.5% in that event.

IIEC notes that AIU witness McShane acknowledges the risk reducing effect of Rider VBA, and by equating Rider VBA to unspecified weather normalization clauses previously examined by S&P, she concludes that her gas cost of equity recommendation should be adjusted by no more than the 10 basis points. IIEC avers that Ms. McShane is silent about Rider QIP's cost of equity effect, and it appears she believes no adjustment is necessary. IIEC submits she contends that Rider QIP is to the benefit of customers because the rider will result in ratepayers being spared the cost of proceedings to examine AIU's proposed infrastructure projects, while she makes no mention of what AIU gains from approval of the rider. IIEC argues that approval of Rider QIP would certainly benefit AIU and should be accompanied by a reduction in the approved return on equity.

While Staff witness Freetly agrees that AIU's risk will be reduced by Rider VBA, IIEC submits that her recommended 10 basis point reduction is inadequate. IIEC further notes that CUB witness Thomas also finds that Rider VBA will have risk reducing effects that warrants a reduction in the recommended authorized gas returns. IIEC avers that Mr. Thomas' analysis of Rider VBA's revenue and cost of equity impacts would have been had it been in place in the past, causes him to recommend a cost of equity reduction of 67.5 basis points. IIEC notes that he further recommends, if Rider QIP is approved, the Commission authorize a reduced return on Rider QIP electric projects.

IIEC submits that the Commission has before it a record that clearly establishes that approval of one or both of the requested riders will reduce AIU's risk. IIEC believes the principles underlying the Commission's consistent approach to determining the appropriate cost of equity for utilities require recognition of the change in the utility's risk that would accompany rider approval. IIEC avers that Section 9-201(c) of the Act requires that the Commission determine an appropriate cost of equity adjustment, since that is a necessary prerequisite for fulfilling the Commission's statutory obligation to determine just and reasonable rates on this record. Although no party may have suggested the perfect resolution in this case, IIEC submits that Mr. Gorman presents the most reasonable of the positions that accord with the reality of AIU's reduced risk under approved riders.

While AIU criticizes Mr. Gorman’s recommendation that AIU's cost of equity be reduced by at least 50 basis points as speculative unsupported by analysis, IIEC submits that it is well-supported, and notes that in the recent Peoples case, the Commission approved just such a judgmental adjustment following approval of a similar rider. IIEC notes that AIU does not criticize Staff’s 10 basis point proposed adjustment, although IIEC submits that Staff’s analysis of risk reducing factors attributable to the rider was equally judgmental. IIEC avers that AIU suggests an adjustment similar to

Staff's, based on treating Rider VBA like a weather normalization adjustment, despite the rider's much broader coverage.

IIEC argues that AIU does not deny that Rider VBA will have an effect on its revenues, its risk, and on its cost of equity, but simply disagrees with IIEC and CUB on the magnitude of that effect. IIEC submits that the burden is on AIU to prove the reasonableness of its proposed rates, including the reasonableness of the elements that make up those rates, and where other parties have presented sufficient support for a risk adjustment, as here, the utility must rebut that evidence. IIEC avers that AIU has not done so, and the evidence shows that a 10 basis point adjustment is inadequate in this instance.

9. Commission Conclusion

As previously noted, AIU accepts Staff's recommended cost of equity for this proceeding. Staff, CUB, and IIEC each present their own cost of equity analyses. Staff witness Freetly's recommendation is based on a discounted-cash flow analysis and CAPM analysis. CUB witness Thomas utilized a constant growth, annual DCF model to estimate AIU's cost of equity. IIEC witness Gorman used a multi-stage DCF model, RP model, and CAPM model.

The Commission notes that Staff has proposed two recommended cost of equity numbers for AIU, dependent on the Commission's decision on AmerenIP's auction rate bonds. As the Commission has earlier rejected AIU's position on the AmerenIP auction rate PCBs, it appears to the Commission that Staff's recommended cost of equity is 10.72% for AIU's natural gas distribution operations, and 10.68% for AIU's electric delivery service operations.

Before the Commission turns to the details of the parties return on equity estimates, it is apparent some parties want the Commission to abandon or deviate from certain past practices in light of new evidence or circumstances. The Commission must balance two competing interests in evaluating such proposals. While the Commission does not wish to totally ignore its past practices, which appear to have served utilities and ratepayers for many years, neither does the Commission wish to engage in cost of equity estimation in a manner that might be viewed as random or arbitrary. The Commission recognizes that it must also consider the possibility that new evidence or research has been developed that should cause the Commission to deviate from past practices. While the Commission recognizes that due to the competing interests present, it is not possible to satisfy all parties, the Commission will undertake to reach well-reasoned conclusions that are based on the record, and consistent with previous Commission decisions, to the extent possible.

a. CAPM

First, the Commission will consider CUB witness Mr. Thomas' recommendation that the CAPM should not be used as a primary tool to estimate cost of equity, but

should only be used to check the reasonableness of the DCF model. He contends that CAPM has such bias in its calculations that it is unreasonable to rely on it to estimate cost of equity. The Commission notes it has considered this argument previously, including most recently the IAWC rate case, Docket No. 07-0507. As the Commission noted there, the only new information or argument presented by CUB appears to be the Nagel Paper, which is discussed in the parties' testimony and briefs.

Mr. Thomas argues that the version of CAPM used by the Commission was rejected in the Nagel Paper, as it had a higher forecast error than the more simplified version. While it appears to the Commission that in the Nagel Paper raw or unadjusted betas were used in CAPM, the Commission can find no suggestion, other than Mr. Thomas' testimony, that adjusted betas were excluded due to forecast error. There does not appear to be any support in the record for Mr. Thomas' assumption that a simplified version of CAPM, where all betas equal 1.0, would have a lower forecast error than the traditional CAPM with the use of adjusted betas. Based upon a review of the record, the Commission is inclined to agree with Staff that the Nagel Paper's finding that using a simplified CAPM where beta is set to 1.0 is superior to the use of unadjusted betas, which tends to support use of adjusted betas, rather than unadjusted betas. The Commission does not believe the record supports a finding that the Nagel Paper undermines the usefulness of CAPM in setting market required returns on equity in utility cases. It appears to the Commission that the Nagel Paper in fact supports the long-standing practice of the use of adjusted betas in CAPM rather than unadjusted betas.

Further regarding CAPM, Mr. Thomas urges the Commission to reject the analyses of Staff and IIEC, as both parties used adjusted betas in arriving at their results, and Mr. Thomas suggests that unadjusted betas are superior when calculating a utility's return on equity. The Commission has reviewed the testimony and arguments of the parties on this issue, and does not find CUB's arguments convincing. The Commission is of the opinion that the continued use of adjusted betas, when combined with appropriate proxy groups, is appropriate and should continue.

The next disputed issue relates to the calculation of EMRP used in the CAPM. Staff developed its EMRP using a DCF derived return on the market, proxied by the S&P 500 less the risk-free rate, which produced a market risk premium of 9.03%. Staff used as its risk-free rate the thirty-year U.S. Treasury Bond yield as of February 14, 2008 of 4.72%, while Staff's DCF estimate of the S&P 500 was 13.75% for the fourth quarter of 2007.

Mr. Gorman relied on historical data to calculate two market risk premium estimates for his CAPM analysis. First, he estimated the expected return on the S&P 500 by adding an expected inflation rate of 2.3% to the 9.1% long-term historical arithmetic average real return on the market over the period 1926-2006. He then subtracted the projected yield on U.S. Treasury bonds of 4.6% to determine the 7.0% market premium. Second, he provided a historical estimate of the market risk premium by calculating the difference between the arithmetic average of the achieved total return

on the S&P 500 of 12.3% and the total return on long-term Treasury bonds of 5.8% over the period 1926-2006, or 6.5%. Both of his market risk premium estimates were derived based on historical returns on the S&P 500.

CUB suggests that should the Commission continue to utilize CAPM in determining the return on equity, then it should adopt CUB's recommendation for the EMRP that will be used in CAPM. CUB states the EMRP represented the expected return on a perfect portfolio of the entire market, in excess of the risk-free rate, and should be the same for all markets and firms being examined in a CAPM analysis, as it is the beta factors, not the EMRP, that differentiate the return estimates for firms of varying risk. CUB suggests that the EMRP is a characteristic that is attributable to all investors and all potential investments, and therefore there is only one EMRP. CUB submits that surveys of investors show that a reasonable estimate of the EMRP that investors expect is in the range of 3.0% to 5.0%, and CUB recommends using a value of 5.0%.

In the Commission's view, IIEC's first EMRP analysis, wherein inflation is added to the average market return and subtracted from projected Treasury bond yields, fails to consider that the real market risk premium is not stable over time, which seems almost a given, as IIEC averaged data from 1926 to 2006. A major shortcoming in IIEC's second analysis is that it relies largely on historical data. As in previous cases, the Commission finds such an approach unacceptable as an average of historical returns is not a reliable predictor of future returns.

CUB alleges that historical market risk premiums have been shown to be consistently too high. CUB suggests that the EMRP adopted for purposes of this proceeding should be based upon Mr. Thomas' review of opinions of members of the financial and academic arenas, which suggest that surveys of investors show a reasonable EMRP to be between 3.0% and 5.0%. The Commission notes that it previously rejected Mr. Thomas' proposed EMRP based on this same reasoning in the most recent IAWC rate case, Docket No. 07-0507. As the Commission indicated there, Mr. Thomas' suggestion does not seem to allow for the EMRP to change over time, which the Commission believes is necessary for any approach or method adopted. Additionally, the suggested EMRP's by the other parties call into question the validity of Mr. Thomas recommendation.

b. DCF

The Commission will next consider the various issues relating to the DCF model and the inputs thereto. Ms. Freetly applied a multi-stage, non-constant growth quarterly DCF model. Mr. Gorman performed both constant growth and non-constant growth DCF models, however, he rejected the use of the constant growth model as its results were based on growth rates that were not sustainable. Mr. Thomas suggests a constant growth, annual DCF model be adopted. The Commission notes that Mr. Thomas has presented no new evidence in support of the annual DCF model. The Commission strongly believes that the quarterly DCF model should be utilized to

estimate the cost of common equity, as demonstrated by numerous previous Commission decisions. It is the Commission's opinion that the use of this model accurately recognizes the timing of cash flows to investors, which is necessary to estimate the investor required rate of return. Use of an annual DCF model, the Commission believes, would unnecessarily introduce measurement error and downward bias to the results.

The Commission notes that it has traditionally relied on a constant growth DCF model with analysts' estimates of EPS growth in developing the cost of common equity for utilities in rate cases. Staff suggests use of a multi-stage, non-constant growth, quarterly DCF model in this proceeding. IIEC suggests the use of a two-stage DCF model, while CUB suggests the use of the constant growth DCF model using historically derived internal growth rates rather than analysts' estimates. Staff and IIEC believe analyst growth rates are so high as to be not sustainable in the long run for use in a constant growth model, and therefore produce too high return on equity results. All parties used proxy groups of gas and electric companies for modeling purposes.

Ms. Freetly modeled three stages of dividend growth for use in her multi-stage, non-constant growth DCF model. For her first stage, she assumed a growth stage of five years. Her second stage is a transitional stage lasting from the fifth to the tenth year, while the third or "steady" stage growth rate begins after the tenth year. For the first stage, Ms. Freetly used the market-consensus expected growth rates from Zacks, for the third-stage she used the 20-year forward U.S. Treasury rate, and the middle stage was an average of the first two rates. The result of her DCF analysis was a suggested return on common equity of 9.41% for the gas sample, and 10.01% for the electric sample.

Mr. Gorman modeled a two-stage, non-constant growth DCF model, where the first stage relied on an average of the consensus of Zack’s, Reuters, and SNL Financial to determine analysts expected growth rates for the first stage of the model. For the second stage of the model, from six years to perpetuity, he assumed each company’s growth would converge on the maximum sustainable growth rate for a utility company as proxied by the consensus analysts’ projected growth for the U.S. GDP. His two-stage non-constant DCF model resulted in a 9.6% suggested return on equity.

The Commission notes that it has rejected CUB's DCF model for its continued use of an annual model, rather than a quarterly model. CUB further suggests that the Commission consider historical internal growth rates, rather than analyst's estimates of future growth in the DCF model, arguing that analyst's estimates have been shown to be overly optimistic. The Commission is of the opinion that for DCF purposes, a forward-looking estimate of at least near term growth rates is appropriate, and will decline to adopt CUB's suggestion. CUB’s approach has been routinely rejected by the Commission, including very recently in Docket No. 07-0507.

The Commission notes that Staff and IIEC are in agreement that at least in this instance, the use of a single-stage, constant growth DCF model is inappropriate, as

analyst's estimates for earnings growth are unreasonably high and are not sustainable for utilities. The Commission agrees with Staff and IIEC that the tradition constant growth model would in this instance, result in suggested growth rates that would exceed the growth rate for the U.S. economy in perpetuity, which appears unlikely. Both Staff and IIEC suggest in this instance, the use of a multi-stage model, with IIEC suggesting a two-stage model, while Staff suggests a three-stage model.

c. Risk Premium Model

Mr. Gorman has also presented the Commission with a risk premium analysis separate from his CAPM analysis. For this model, Mr. Gorman used two estimates of risk premium to develop a range to define the cost of equity. The first estimate was based on the difference between commission authorized returns on common equity, and Treasury bond yields. For the second estimate, Mr. Gorman calculated the difference between commission authorized returns on common equity and contemporary A-rated utility bond yields.

Mr. Gorman's analyses resulted in a return on equity estimate in the range of 9.8% to 10.2%, with a mid-range estimate of 10.0%. It appears to the Commission that Mr. Gorman's risk premium model suffers from the same deficiency as the EMRP used in his CAPM analysis, as it relies on historical returns in an attempt to calculate a forward-looking number. As such, the Commission will decline to use Mr. Gorman's risk premium analysis in determining the authorized return on equity for AIU.

d. Adjustment for Reduced Risk of Gas Operations

While the Commission’s complete analysis and decision on Rider VBA and Rider QIP can be found in later parts of this Order, the Commission notes that at this time, it is not authorizing the implementation of either Rider by AIU. The Commission does however, in the Rate Design section of this Order, make the decision to authorize recovery of more of AIU's fixed costs through the customer charge. The Commission is of the opinion that this move toward AIU recovering more fixed costs through the fixed monthly charge will have a similar effect as adopting Rider VBA, in that AIU will be more assured of recovering its fixed costs of service for gas operations. As a result, AIU will face less risk and an accompanying reduction in the authorized return on equity is warranted. Although none of the parties addressed this result directly, the discussions and analyses on the effects of Rider VBA and Rider QIP are helpful to the Commission in its consideration of the appropriate level of reduction in risk associated with increasing the fixed customer charge to account for a greater portion of fixed costs. While the Commission recognizes that this change lessens the risk for AIU to recover fixed gas charges, there is still some risk remaining that reduced natural gas consumption could result in an under-recovery situation. As such, the Commission deems it appropriate to adjust AIU's authorized return on equity for its gas operations downward by 10 basis points. The Commission is of the opinion this reduction adequately reflects the changes adopted in the rate design portion of this Order, and reflects that AIU's risk of not recovering its fixed costs will have been reduced.

e. Authorized Returns on Equity

Having addressed the significant contested issues that relate to cost of common equity, it appears to the Commission, as discussed above, that there are significant shortcomings with respect to the analysis of CUB witness Thomas. The Commission has indicated that it will again decline to adopt his suggestion to use an annual growth DCF mode that incorporates historically derived internal growth rates. Likewise, his suggestions concerning CAPM are rejected, along with his suggested EMRP. Likewise, Mr. Gorman's Risk Premium and CAPM analysis are rejected and will not be considered as they rely too heavily on historical returns in calculating a forward looking recommended return on equity.

The Commission finds value in both Staff's and IIEC's DCF analyses, along with Staff's CAPM analysis. Each has suggested the use of a multi-stage DCF model in this instance to mitigate the impact of unsustainable analyst estimates of growth, using instead estimated proxies of U.S. GDP growth as the long-term growth rate. Staff's DCF analysis, based on a three-stage model, results in a recommended return on equity of 9.41% for AIU's gas operations, and 10.01% for AIU's electric operations. IIEC's DCF analysis, using a two-stage approach, results in a recommended return on equity for both electric and gas operations of 9.6%. Staff's CAPM analysis resulted in a cost of equity recommendation of 12.04% for AIU's gas operations, and 11.94% for AIU's electric operations.

The Commission finds IIEC's DCF analysis, along with Staff's DCF and CAPM analyses, to be without material flaws, and should be considered in establishing AIU's cost of common equity. The Commission further notes that Staff proposes to adjust its recommended electric results downward by 30 basis points, as Staff determined that AIU was less risky than the electric proxy group. The Commission notes this adjustment appears uncontested and it will be adopted for calculating Staff's recommended return on equity.

Having reviewed the evidence and arguments, the Commission concludes that AIU's cost of common equity is 10.68% for gas operations and 10.65% for electric operations. These returns on common equity give equal weight to the results of Staff and IIEC DCF analyses, which is combined with Staff's CAPM analysis. As indicated above, the authorized return on equity for AIU's natural gas operations is adjusted downward by 10 basis points to reflect the change in Rate Design adopted in this Order.

	GAS		ELECTRIC	
Party	DCF	CAPM	DCF	CAPM
Staff	9.41%	12.04%	9.71%	11.64%
IIEC	9.60%		9.60%	
Average	9.51%	12.04%	9.65%	11.64%
Midpoint	10.78%		10.65%	
Risk Adjustment	(0.10)%			
AUTHORIZED RETURN ON EQUITY	**10.68%**		**10.65%**	

10. Commission Authorized Rates of Return on Rate Base

Taking into consideration the Commission's conclusions regarding capital structure, cost of short-term debt, cost of long-term debt, and cost of common equity, the Commission finds that AmerenCILCO should be authorized to earn an 8.01% rate of return on net original cost rate base for electric operations; AmerenCIPS should be authorized to earn an 8.20% rate of return on net original cost rate base for electric operations; and AmerenIP should be authorized to earn an 8.68% rate of return on net original cost rate base for electric operations. The tables below show the development of that authorized rate of return:

Electric Operations
AmerenCILCO

Component	Amount	Percentage	Cost	Weighted Cost
Short-term debt	72,643,527	15.53%	4.04%	0.63%
Long-term debt	141,064,706	30.17%	6.65%	2.01%
Preferred stock	36,450,067	7.79%	5.34%	0.42%
Common equity	217,459,214	46.50%	10.65%	4.95%
Total	467,617,514	100%		8.01%

AmerenCIPS

Component	Amount	Percentage	Cost	Weighted Cost
Short-term debt	55,210,979	5.22%	4.01%	0.21%
Long-term debt	446,741,385	42.24%	6.27%	2.65%
Preferred stock	48,974,984	4.63%	5.13%	0.24%
Common equity	506,691,386	47.91%	10.65%	5.10%
Total	1,057,618,734	100%		8.20%

AmerenIP

Component	Amount	Percentage	Cost	Weighted Cost
Short-term debt	76,677,769	3.69%	3.93%	0.15%
Long-term debt	709,096,036	34.10%	7.34%	2.50%
TFTN	171,533,494	8.25%	4.92%	0.41%
Preferred stock	45,786,945	2.20%	5.01%	0.11%
Common equity	1,076,124,965	51.76%	10.65%	5.51%
Total	2,079,219,209	100.00%		8.68%

Taking into consideration the Commission's conclusions regarding capital structure, cost of short-term debt, cost of long-term debt, and cost of common equity, the Commission finds that AmerenCILCO should be authorized to earn an 8.03% rate of return on net original cost rate base for gas operations; AmerenCIPS should be authorized to earn an 8.22% rate of return on net original cost rate base for gas operations; and AmerenIP should be authorized to earn an 8.70% rate of return on net original cost rate base for gas operations. The tables below show the development of that authorized rate of return:

Gas Operations
AmerenCILCO

Component	Amount	Percentage	Cost	Weighted Cost
Short-term debt	72,643,527	15.53%	4.04%	0.63%
Long-term debt	141,064,706	30.17%	6.65%	2.01%
Preferred stock	36,450,067	7.79%	5.34%	0.42%
Common equity	217,459,214	46.50%	10.68%	4.97%
Total	467,617,514	100%		8.03%

AmerenCIPS

Component	Amount	Percentage	Cost	Weighted Cost
Short-term debt	55,210,979	5.22%	4.01%	0.21%
Long-term debt	446,741,385	42.24%	6.27%	2.65%
Preferred stock	48,974,984	4.63%	5.13%	0.24%
Common equity	506,691,386	47.91%	10.68%	5.12%
Total	1,057,618,734	100%		8.22%

AmerenIP

Component	Amount	Percentage	Cost	Weighted Cost
Short-term debt	76,677,769	3.69%	3.93%	0.15%
Long-term debt	709,096,036	34.10%	7.34%	2.50%
TFTN	171,533,494	8.25%	4.92%	0.41%
Preferred stock	45,786,945	2.20%	5.01%	0.11%
Common equity	1,076,124,965	51.76%	10.68%	5.53%
Total	2,079,219,209	100.00%		8.70%

VII. PROPOSED RIDERS

Among the Proposed Tariffs filed by AIU are its proposals for several new revenue generating riders. Rider UBA-Uncollectibles Balancing Adjustment, Rider UBBA-Uncollectibles Balancing Base Rate Adjustment, and Rider UBPA-Uncollectibles Balancing Purchased Power Adjustment concern amounts billed to electric and gas customers that have not been paid. Although it continues to believe that the manner in which it recovers uncollectibles warrants further consideration, in his rebuttal testimony, AIU witness Nelson indicated that AIU is withdrawing its request for approval of these three riders concerning uncollectibles. (See Ameren Ex. 18.0 at 5) Other proposed riders that AIU still supports are Rider VBA-Volume Balancing Adjustment ("Rider VBA"), applicable to residential and small commercial gas delivery service customers, and Rider QIP-Qualifying Infrastructure Plant Surcharge ("Rider QIP"), applicable to electric delivery service customers. Rider VBA and Rider QIP will be considered separately below.

A. Rider VBA

1. AIU's Position

The two components of AIU's gas cost of service are gas supply and gas delivery. The cost of the natural gas supply itself is recovered through the PGA rider. About 97% of gas delivery cost is recovered through tariff base rates primarily consisting of customer charges, volumetric delivery charges, and, for certain larger customer groups, demand charges. The remaining portion (about 3%) of delivery service cost is recovered through “other” tariff charges (e.g., late pay charges, insufficient fund charges, disconnect/reconnect fees, etc.). Of the fixed delivery service cost recovered through customer charges, volumetric delivery charges, and demand charges, AIU indicates that approximately 43% of its fixed delivery service cost is recovered based on the volume of gas used by customers. The vast majority of the remaining fixed delivery service cost recovery comes from the monthly customer charge.

Because a significant portion of its fixed costs are recovered through the volatile volumetric component, AIU observes that it could significantly over- or under-recover

the cost of service from year to year due to fluctuations in usage. AIU indicates that such fluctuation has occurred, but that it has been decidedly one-sided. AIU reports that the level of sales it has experienced has been consistently lower than that assumed in the test year, even in the very first year after a rate order. According to AIU, this has caused it to under-recover its cost of service, and thus it has not earned the authorized rate of return.

The three principal factors that AIU identifies as being responsible for sales differing from forecasted levels are (1) weather, (2) a general decline in natural gas usage, and (3) targeted gas energy efficiency measures. With regard to weather, when recovering fixed costs through volumetric rates, smaller customers are apt to pay more toward fixed costs in colder weather when they use more gas for heating and pay less toward fixed costs in warmer weather when they do not use as much gas for heating. Gas usage is also generally declining across the industry according to AIU, so any efforts to recover fixed delivery costs through a volumetric rate will likely suffer over time. AIU attributes at least some of the general decline to gas appliances becoming more efficient and there being no significant new domestic uses for gas. Despite this explanation for the decline in gas usage, Mr. Nelson indicates that AIU has not yet experienced much of an impact from the third factor.

AIU also points out that volumetric delivery rates pose a problem in regard to energy efficiency initiatives. When utility revenue is tied to the volume of gas sold, AIU observes that the utility has no incentive to encourage conservation and the efficient use of gas. If this disincentive is removed, AIU witness Hanser indicates that AIU is willing to participate in a collaborative stakeholder process to identify specific energy efficiency measures to be implemented and the amount to be expended on each.[9]

AIU seeks to remove this disincentive by "decoupling" the recovery of fixed delivery service costs from the amount of gas sold through its proposed Rider VBA. Generally, under a decoupling rider, on a periodic basis revenues are “trued-up” to the predetermined revenue requirement using an automatic rate adjustment. The result is that the actual utility revenues should more closely track its projected revenue requirements, and should not increase or decrease with changes in sales. Citing research conducted by the National Association of Regulatory Commissioners ("NARUC"), AIU relates that ten other states have approved decoupling and three states and the District of Columbia are investigating decoupling. AIU adds that 13 of the 14 states mentioned also have energy efficiency programs. AIU adds that energy efficiency programs conducted in conjunction with a decoupling rider provide societal and economic benefits, which ultimately benefit customers.

If the Commission is inclined to approve Rider VBA, AIU states that Rider VBA is designed to operate in the same manner as the Peoples/North Shore decoupling rider

[9] AIU filed with the Commission proposed gas efficiency measures resulting from the collaborative effort, initiating Docket No. 08-0104. The gas efficiency filing identifies the definitive programs, the associated cost of the programs, and a proposed rider for recovery of the costs. Docket No. 08-0104 is currently on-going.

approved by the Commission as a four-year pilot program in consolidated Dockets Nos. 07-0241 and 07-0242 on February 5, 2008. Rider VBA would adjust customer rates each month based on changes in per customer usage for the residential (GDS-1) and small commercial (GDS-2) customer classes based on an AIU-configured usage-per-customer benchmark. A monthly surcharge would be imposed if per-customer usage in the rate classes falls below a baseline set in this proceeding (regardless of the reason for the decline), without examining whether overall revenues have increased. AIU has agreed to implement Rider VBA in the context of a pilot program that would terminate on December 31, 2012. AIU is also willing to provide the Commission with an annual report of the rate of return of AmerenCILCO, AmerenCIPS, and AmerenIP and the effect on that return of Rider VBA. AIU further agrees that the Rider VBA formula should be designed to recover only the utility's fixed costs that are reflected in the revenue requirement recovered via the volumetric delivery charge.

These commitments, AIU argues, sufficiently counter the concerns of AG/CUB witness Brosch that the Commission will inadvertently allow unreasonable earnings when it evaluates rider recovery of costs on an annual basis. To the extent that the rate of return reports are not sufficient, AIU states that the Commission can request further information, which AIU has a duty to respond to pursuant to Section 5-101 of the Act. The "pilot" nature of Rider VBA should also help to resolve the concerns of Mr. Brosch because if renewal of the rider is desired, changes can be made based upon what stakeholders have learned from the pilot program

AIU also responds to Mr. Brosch's assertion that Rider VBA is asymmetrical, in that it only benefits AIU. AIU insists that Rider VBA is plainly symmetrical, meaning that if a colder than normal winter were to occur customers would receive credits for the higher than anticipated consumption and vice versa. AIU witness Cooper even testifies that had Rider VBA been in place this past winter, customers would have received credits in three of the four winter months. AIU contends that Rider VBA will simply track the volumetric cost collection per customer and true-up to prevent either the under- or over-recovery of Commission approved fixed costs for test year customer levels. Moreover, setting aside the question of symmetry for a moment, AIU notes that Mr. Brosch does not address the central issue: that given today's contemporary fossil fuel issues, establishing rates that give utilities an incentive to sell more natural gas is a policy that no longer makes sense.

AIU further contends that the AG's legal arguments against Rider VBA are misplaced. Citing Citizens Utility Board v. Illinois Commerce Commission, 166 Ill.2d 111, 123-9 (1995), AIU asserts that the Commission has discretion to allow rider recovery in a proper case and the legal authorization to approve riders will not be reversed absent an abuse of discretion. Under City of Chicago v. Illinois Commerce Commission, 218 Ill.App.3d 617, 628 (1st Dist. 1996), AIU also states that rider recovery is not limited only to circumstances where unexpected, volatile, and fluctuating costs are present.

In response to Staff witness Ebrey, AIU denies that Rider VBA represents only "partial" decoupling since it would not reflect changes in the number of gas customers. In contrast to Ms. Ebrey's proposal and commentary, AIU states that it is not seeking to isolate its revenue from "all changes" that may occur in the course of the operation of its gas utility businesses. Rather, AIU indicates that it is seeking to decouple Commission approved rate recovery for test year customer levels from changes in volumetric consumption, specifically due to declining usage trends and weather patterns. AIU characterizes Rider VBA as "plain vanilla" decoupling, and asserts that it is not intended to operate differently from what was granted in Docket Nos. 07-0241 and 07-0242 (Cons.). AIU insists that Rider VBA is "full decoupling" since the volumetric component of its rates are to be trued-up on a margin per customer basis to insure each customer pays his/her share of fixed costs.

If actual (i.e., post test year) customer count data is incorporated, AIU maintains that Rider VBA no longer remains a rate design vehicle designed to recover Commission approved revenue requirements for test year customer levels. Rather, it becomes a broader formulaic rate that essentially will function to alter the revenue requirement equation established by the Commission in this docket on an annual basis. Additionally, AIU contends that Ms. Ebrey's method would do so asymmetrically because her recommendation has not articulated any mechanism by which AIU would be permitted to include costs associated with changes in the number of customers, or by which AIU would be permitted to prove up the value of the plant assets necessary to meet customer growth. Such a situation, AIU argues, essentially amounts to single-issue ratemaking.

Under Ms. Ebrey's proposal, AIU claims that the lack of symmetry would be so prejudicial to its interests, that it would be confiscatory. Essentially, AIU continues, Ms. Ebrey's proposal would function to annually reduce AIU rates by spreading the revenue requirement across a broadening customer base as new customers are added while it completely ignores costs associated with such load growth. Thus, AIU contends that it is inevitable that a changing or increasing cost of service due to plant and expenses associated with new customers with unchanging revenue would not afford AIU a reasonable opportunity to earn the rate of return approved by the Commission herein.

Conversely, AIU points out that it is not explained how customers would be impacted by the potential of an automatic rate increase if customer numbers were to contract in a given year. It is not clear how such a situation would fit within the constructs of the Act. While it is uncommon for customer count reductions to occur, AIU contends that demographic shifts such as population decline in certain areas, or sudden and dramatic increases in natural gas cost can result in customer count reductions. Without any consideration in the record of such issues, AIU urges the Commission to decline to add customer count variables to the Rider VBA formula.

With respect to Staff's assertion that it would be illogical to have identical decoupling pilot programs for both AIU and Peoples/North Shore, AIU believes otherwise. AIU contends that having multiple gas utilities in Illinois with the same pilot

program insures that the results of the pilot program are not skewed by some operational condition a single utility. Under its proposal, AIU states that the Commission will have a diversity of data to analyze.

An alternative to Rider VBA that would still promote full fixed cost recovery by the utility is recovery of all fixed delivery costs through a fixed monthly charge to all affected customers. Under such a rate design, AIU states that utilities could not over- or under-recover their Commission-approved base rate revenue requirement with changes in sales. AIU adds that this alternative would also send proper price signals to customers. AIU indicates that it can either implement the fixed monthly charge concept as described above, or implement Rider VBA which would continue to retain a volumetric rate design component and, also, ensure a precise match between actual revenue and those previously approved by the Commission. Another alternative, AIU continues, would be to adjust the test year billing determinants for a downward trend in sales due to efficiency gains, but this is the less preferable option because it involves guesswork, whereas the fixed charge option does not.

2. Staff's Position

Staff has not made policy or rate design recommendations regarding whether Rider VBA should be approved in these proceedings. Staff has, however, proposed a number of modifications to the rider in the event the Commission decides to approve decoupling for AIU. First, Staff recommends that the Commission incorporate the additional safeguards it approved in Docket Nos. 07-0241/07-0242 (Cons.). Staff notes that AIU has agreed to modify Rider VBA to reflect any differences between the Rider VBA as filed in these proceedings and the Rider VBA approved in Docket Nos. 07-0241/07-0242 (Cons.). Staff does not take issue with the slight revisions to the proposed language addressing an annual internal audit of Rider VBA proposed by AIU.

Staff's second proposed modification involves a discussion of "full" versus "partial" decoupling. Staff witness Ebrey proposes that “full decoupling” be approved as a pilot program in this proceeding (if Rider VBA is to be approved) rather than the same program design that is already in pilot status for North Shore and Peoples, which is “partial decoupling.” She states that “full decoupling," as described in the NARUC document titled, “Decoupling For Electric & Gas Utilities: Frequently Asked Questions (FAQ)”, provided by AIU in response to AG data request 3.03d Attach (Staff Group Ex. 1), adjusts utility revenues for any deviation between expected and actual sales regardless of the reason for the deviation. Thus, Ms. Ebrey continues, it “decouples” revenues from any and all variations between actual operations and those predicted by the revenue requirement. Staff asserts that the variation of the full sales decoupling proposed by AIU is called “Sales-Margin Decoupling,” which separates margin recovery from sales by setting a margin-per-customer target. (Id.) Since the proposed AIU and approved North Shore and Peoples decoupling riders are both based on the same "partial” decoupling, Staff avers that it would not be logical to approve for AIU a program design identical to the one approved for North Shore and Peoples as a pilot program. The result would be three identical pilot programs; nothing would be gained from such

an exercise. According to Staff, however, a Rider VBA program based on “full” decoupling as Staff proposes as a pilot program for AIU would provide the Commission with another alternative for comparison at the end of the pilot periods to determine which form of decoupling is preferable for Illinois utilities.

The third modification proposed by Staff concerns the adjustment calculation in Rider VBA to reflect “full" decoupling, should the Commission decide to approve the rider. Staff understands that the intent of Rider VBA is to assure dollar-for-dollar recovery of the portion of fixed costs currently recovered through the volumetric portion of delivery service charges. The proposed rider has an annual reconciliation mechanism which AIU says will only allow it to recover the Commission approved revenue requirements and not a dollar more. Staff, however, is not sure that the reconciliation mechanism can be relied upon to limit recovery to the approved revenue requirements.

In discussing its concern, Staff explains that Rider VBA has two main formulas: one to determine the Effective Component which calculates the Rider VBA charge to be applied to the Effective Month, and the other to determine the Reconciliation Adjustment for the annual true-up. The Effective Component formula calculates any over or under recovery of the fixed cost portion of the volumetric charges on a per customer basis as opposed to a total revenue requirement basis. Since any Commission-approved revenue requirement is based upon a projected number of customers, if AIU's actual number of customers exceeds that projected level, Staff indicates that there appears to be a possibility that AIU could collect more fixed costs through Rider VBA than approved in the revenue requirement. Specifically, AIU would collect more fixed costs from the additional customers’ volumetric charges and from their monthly customer charges. Staff states that this would not be a concern if there were specific provisions in the proposed rider that would address this issue; however, there are none. Staff offers an example in its Initial Brief setting forth its concern. (Staff Initial Brief at 253)

Staff further explains that in approving the decoupling rider for North Shore and Peoples, it was implied that fixed costs are costs that are necessary to operate the utility regardless of any changes to the operation--a “fixed” cost of doing business regardless of the amount of business conducted. Converting the fixed costs to be recovered to a per customer basis suggests to Staff, however, that the costs are not truly fixed but that they will vary with the number of customers served. Staff contends that additional customers over the level assumed in the revenue requirement would not necessarily result in additional fixed costs to AIU. AIU claims that the “overwhelming majority” of its delivery system revenue requirements do not “vary” with the volume of natural gas consumed by customers and is thus “fixed” in nature. (AIU response to Staff data request TEE 15.05) In furtherance of this claim, AIU states that the only variable costs that the gas utilities have that are not recovered through the PGA clauses relate to odorant expense. (AIU response to Staff data request TEE 15.08) Staff points out, however, that AIU also claims, “Such statement is not intended to mean that [AIU] cost of service or revenue requirements are 'fixed' for any period of time.” (AIU response to Staff data request TEE 15.05) If costs vary based on any changes to the operations,

including changes in the number of customers served, Staff believes that they can not be truly fixed costs. Staff contends that AIU has had the opportunity to provide support for how it defines "fixed" costs, clarify its statement that the costs under consideration are not fixed for any period of time, identify the total dollar amount of fixed costs it is seeking to recover in its proposed revenue requirement, and separately identify the portions of those fixed costs of service that it is seeking to recover from the customer charge and from the volumetric usage charge. Staff asserts that no such support has been provided in the record.

Implementation of Staff's third proposed revision to Rider VBA would first require AIU to identify those costs that are truly fixed. Modifying the Effective Component formula in the rider such that it is not calculated on a per customer basis but based on the total fixed cost component of the approved revenue requirement would follow. Specifically, Staff recommends that if the Commission approves Rider VBA that it modify the Effective Component formula as follows:

1. Effective Component

   The adjustment, determined for each Rate, to be billed for the Effective Month is represented by the following formula:

   [(RCBR ~~/ RCC~~) – (ABRR ~~/ AC~~)] ~~x RCC~~ / T x 100

   Where:

   RCBR represents the Rate Case Base Rate Revenue for the Reconciliation Month.

   ~~RCC represents the number of Rate Case Customers for the Reconciliation Month.~~

   ABRR represents the Actual Base Rate Revenue for the Reconciliation Month.

   ~~AC represents the number of Actual Customers for the Reconciliation Month.~~

   T represents the forecast Factor T for the Effective Month.

3. AG's Position

The AG argues that Rider VBA violates several critical ratemaking precepts and should be rejected. Setting aside the many legal infirmities of the proposed rider, the AG also argues that the evidence in no way demonstrates that a need for Rider VBA exists. Rider VBA, the AG asserts, would trigger piecemeal rate adjustments for

isolated elements of utility revenue requirements in the absence of compelling evidence that such piecemeal rate adjustments are warranted.

A review of the AG's position begins with its observation that both the Act and Illinois court rulings regarding the utility ratemaking process provide an essential regulatory and legal framework for the Commission's analysis of Rider VBA. When the Commission enters upon a hearing to review a utility's proposed rate increase pursuant to Section 9-201 of the Act, it must determine whether the proposed rates are just and reasonable and do so within the regulatory parameters which prohibit retroactive and single-issue ratemaking. (See BPI II, 146 Ill.2d at 195) Following the discussion of the AG's legal analysis is a review of its policy arguments.

a. Legal Considerations

The AG raises several legal arguments against Rider VBA. The first argument concerns single-issue ratemaking. For utility ratemaking purposes, the AG states that riders are closely scrutinized because of the danger of single-issue ratemaking. (See City of Chicago v. Illinois Commerce Commission, 281 Ill.App.3d 617 (1st Dist. 1996)) The rule against single-issue ratemaking is a ratemaking principle which recognizes that the revenue requirement formula is designed to determine a utility's revenue requirement based on the utility's aggregate costs and demand. The rule prohibits the Commission from considering changes to components of the revenue requirement in isolation. As noted by the AG, limited exceptions to the rule against single-issue ratemaking exist. Based on the case law and statutory authorizations issued to date, the AG recounts that Commission decisions implementing riders for the recovery of certain expenses have not been reversed by Illinois courts as illegal single-issue ratemaking when the expenses at issue are (1) unexpected, volatile, or fluctuating, (2) imposed on the utility by law, including federal and state law (such as environmental clean-up expenses) and municipal ordinance for a unique purpose (such as franchise fees), or (3) specifically authorized by statute. The AG avers that fluctuations in gas usage within a customer class do not fall within one of these categories. In contrast, the AG believes that a rider focusing solely on such fluctuations without regard for all other circumstances is a prime example of single-issue ratemaking.

The AG's second legal argument is that Rider VBA contradicts ratemaking principles established by the U.S. Supreme Court. In the case Bluefield, the Court established that a utility's rates should reflect the opportunity – not a guarantee – to earn a return on its used and useful property when a commission sets rates. In spelling out the factors to be examined by regulators when establishing a utility's rate of return, the high court held that a public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. The Court further held that a utility has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. (Bluefield, 262 U.S. at 692-693) The Court

specified that the return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. (Id. at 693) The Supreme Court also recognized that changes in the marketplace may impact a utility's financial health and the appropriateness of the rates being charged, when it held that a rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. (Id. at 692)

The AG observes that the U.S. Supreme Court elaborated on the principles governing rate of return regulation in the case of Hope. In Hope, the Supreme Court held that investors have a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. But in Market St. Ry. Co. v. Railroad Commission, 324 U.S. 548 (1945), the AG reports that the Court specifically rejected the notion that a monopoly must be protected from market realities, such as competition or the effects of price on a consumer's demand and use of the service. The Court explained, "Even monopolies must sell their services in a market where there is competition for the consumer's dollar and the price of a commodity affects its demand and use." (Id. at 568)

Illinois courts have adopted the Bluefield and Hope standards and applied them to the regulation of utilities in Illinois. (See Illinois Bell Telephone Co. v. Illinois Commerce Commission, (1953), 414 Ill. 275) Moreover, the AG adds, Illinois appellate courts have declared that it is the ratepayers' interest which must come first:

> The Commission has the responsibility of balancing the right of the utility's investors to a fair rate of return against the right of the public that it pay no more than the reasonable value of the utility's services. While the rates allowed can never be so low as to be confiscatory, within this outer boundary, if the rightful expectations of the investor are not compatible with those of the consuming public, it is the latter which must prevail. (Camelot Utilities, Inc. v. Illinois Commerce Commission, 51 Ill.App.3d 5, 10, 365 N.E.2d 312 (1977), See also Citizens Utility Board v. Illinois Commerce Commission, 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995))

These and the previously discussed holdings suggest, according to the AG, that AIU's request for the guaranteed recovery of the approved per customer "margin revenue" stream established when rates are set in this case through Rider VBA has no support in the utility regulatory law that has guided this Commission's establishment of rates.

The third legal argument made by the AG is that the circumstances at hand do not warrant the extraordinary regulatory treatment of a rider. In the case of A. Finkl & Sons Company v. Illinois Commerce Commission, 250 Ill.App.3d 317, 620 N.E.2d 1141 (1st Dist. 1993) ("Finkl"), the Illinois Appellate Court held that riders are useful in

alleviating the burden imposed upon a utility in meeting *unexpected, volatile,* or *fluctuating* expenses. (Id. at 327) (emphasis in original) In addition, the AG observes that the court noted that the amount of costs to be recovered through the rider at issue in the case was not significant, and were recoverable through the usual rate case mechanism. The criteria enunciated in Finkl for determining whether a utility expense should be recovered through a rider was affirmed by the Illinois Supreme Court in Citizens Utility Board v. Illinois Commerce Commission, 166 Ill.2d 111, 651 N.E.2d 1089 (1995). While the Court upheld the Commission's approval of rider recovery of coal tar clean-up expenses in the case, it affirmed the criteria relied upon in Finkl for rider recovery of expenses, noting that the coal tar remediation expenses commonly incurred to comply with the mandate of federal and state law are sufficiently volatile and not within management's control to justify rider recovery.

In applying the Finkl standard to AIU's declining revenue situation, the AG examined the impact of Rider VBA had it been in place beginning in 2002. The AG reports that the largest annual margin dollar change would have been a margin revenue increase of $18.6 million in 2006. Although this amount is not insignificant, the AG asserts that it is not particularly large in relation to the total test year operating income of $272 million proposed by AIU in this proceeding. The AG does not consider this amount large enough to warrant rider treatment under Finkl. Nor does the AG believe that historical fluctuations in gas usage due to weather count as unacceptable levels of volatility under Finkl. The AG also suggests that AIU management has some control over usage in light of AIU witness Nelson's comments regarding energy efficiency programs.

The fourth legal argument raised by the AG concerns the Act's requirement in Sections 1-102 and 8-401 that utility rates be least-cost. The AG contends that implementation of Rider VBA will permit piecemeal rate increases that violate this requirement. Had Rider VBA been in effect from 2004 through 2006, the AG reports that AIU would have collected an additional $38.8 million in gas delivery charges. If AIU's predictions about declining gas usage per customer are correct, the AG states that Rider VBA's monthly adjustment of customer rates will not produce rates that are "least-cost," as required by the Act.

The AG's fifth argument is that Finkl prohibits recovery of revenues lost due to energy efficiency and conservation efforts. In Finkl, the AG reports that the appellate court flatly rejected the notion of making a utility whole for lost revenues associated with conservation or demand side management programs. Given the parallels between the rider at issue in Finkl and Rider VBA, the AG contends that implementation of Rider VBA would be illegal.

The sixth legal argument is that Rider VBA violates the Act's prohibition against discrimination in rates. Section 9-241 of the Act prohibits any utility from establishing or maintaining any unreasonable difference in rates or other charges between customer classes. AIU seeks to maintain a designated level of revenues per customer on a monthly basis after rates are set in this proceeding for residential and small commercial

classes, but not for the other rate classes served by AIU. Although AIU argues that a decoupling rider is needed because declines in usage per customer cause a significant under recovery in the fixed cost of service and an inability to earn authorized returns, the AG asserts that nowhere in any AIU witness' testimony does there exist evidence that decreases in usage per customer are limited to residential and small commercial customers. Nevertheless, Rider VBA does not apply to other customer classes. Therefore, according to the AG, Rider VBA constitutes unreasonable discrimination against residential and small commercial customers. The AG avers that adjusting the monthly charges to these customer classes, based on changes in future gas usage (and the margin revenues produced), from the baseline level of revenues per customer established in this case, but not for AIU's other customer classes, contradicts the prohibition in Section 9-241 against unreasonable discrimination between customer classes.

b. Policy Considerations

A part of any rate case, the AG relays, is the "matching principle," which recognizes the importance of matching within the test year all revenues and costs (expenses, rate base, rate of return) to determine needed changes in utility service pricing. As long as revenues and costs remain in approximate balance, causing a utility's earnings to stay within acceptable proximity to authorized return levels, the utility may be able to go many years between rate cases. The fundamental problem with riders, the AG argues, is the potentially serious distortion of the matching principle under traditional ratemaking that occurs when a single expense item is tracked in isolation, thereby ignoring other changes occurring to expenses and revenues that affect a utility's revenue requirement.

A related concern of the AG is that implementation of any rider focusing on a single expense item will eliminate or reduce the incentive for utility management to control and reduce costs. Because rates are typically fixed for a period of years, the AG asserts that the regulatory lag that occurs provides utility management with efficiency incentives and symmetrical risks and opportunities for both ratepayers and shareholders -- depending on cost and revenue trends -- between rate cases. The AG notes that regulatory lag has worked out well for AmerenCILCO's gas operations, which AIU admits is currently over earning. Another advantage of traditional test year ratemaking over riders identified by the AG is the intensive focus upon utility operations and costs that occurs in a rate case in which Staff and other interested parties can carefully examine the components making up the revenue requirement.

In addition to the reduction in management incentives (resulting from eliminating regulatory lag), AG/CUB witness Brosch identifies other concerns stemming from rider recovery of certain rate elements:

- Shifting of cost responsibility and risk to customers who are least able to influence cost levels or sales levels;

- Increases in tariff and bill complexity that may be difficult to explain to customers or that may complicate customers' ability to control their costs;
- Administrative complexity and additional costs associated with audit verification and administration of complex accounting entries, cost allocations and/or tariff calculations, often on an accelerated procedural schedule; and
- Potential for inadequate regulatory oversight and auditing of rider tariffs.

Given the importance of the matching principle in traditional ratemaking and the potential problems inherent in rider recovery of rate elements, the AG contends that exceptions to normal test year ratemaking should only be allowed when extraordinary circumstances exist that preclude the setting of just and reasonable rates through the traditional test year process. The AG maintains that there has been no showing by AIU of any extraordinary circumstances sufficient to justify departing from the continued balanced regulation of future changes in AIU's costs and revenues via periodic rate cases.

Mr. Brosch testifies that costs or revenue changes to be tracked through a rider should generally have *all* of the following characteristics to merit the exceptional and preferential treatment inherent in riders:

- Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases;
- Beyond the control of management, where utility management has little influence over experienced revenue or cost levels;
- Volatile in amount, causing significant swings in income and cash flows if not tracked;
- Straightforward and simple to administer, readily audited and verified through expedited regulatory reviews; and
- Balanced, such that any known factors that mitigate cost impacts are accounted for in a manner that preserves test year matching principles.

The AG asserts that it is no coincidence that the general criteria for rider treatment that are cited and discussed by Mr. Brosch are closely aligned with the factors considered and adopted in the Commission and Illinois court cases cited above. The AG maintains that AIU has failed to make a case that extraordinary rider treatment of revenues lost due to declines in usage per customer is needed from a financial perspective in order for AIU to have a reasonable opportunity to achieve a fair return on investment.

The arguments that AIU has made in support of Rider VBA are meaningless red herrings in the AG's view. In response to AIU's claim that full recovery of fixed costs is at risk because a portion is based on volumetric charges, the AG counters that AIU fails to acknowledge that the Commission sets rates after considering normal weather and the estimated number of bills that a utility expects to issue. Focusing on margin revenues per customer, the AG continues, also ignores the fact that AIU's revenue streams and expenses are dynamic. For instance, revenue from new customers may

compensate for existing customers' decreased usage. Improvements in productivity can also reduce expenses to compensate for existing customers' decreased usage.

The AG states further that under AIU's ratemaking paradigm a natural gas delivery utility should be made whole for all per customer load losses, no matter whether the decline in usage is due to conservation efforts, customers' desire to dial down the thermostat and reduce winter heating bills in response to high gas prices, or the prevalence and installation of more efficient appliances. Moreover, according to the AG, AIU witness Cooper confirmed that as customers increase their efforts to conserve natural gas, their delivery service rates will increase. (Tr. at 539-540) The AG is troubled that the amount of natural gas service used by a customer becomes irrelevant to the amount of money owed to the utility for gas delivery service. When usage per customer declines, AIU generally and theoretically asserts that its overall revenues and profits decline and its cost of service is not fully recovered. Even when revenues collected from new customers offset the impact of reduced usage by existing customers so that there is no loss in overall revenues, the AG understands that a surcharge may nonetheless be imposed on residential and small commercial customer bills under Rider VBA. Similarly, the AG also understands that even if total revenues exceed the level approved in this rate case, a surcharge will be imposed if use per customer declines.

Conspicuously absent from the record, the AG avers, is any evidence that overall margin revenues have dropped precipitously or become unstable in the years since AIU's last gas rate case so as to justify the unorthodox ratemaking treatment that Rider VBA brings. Moreover, the AG states that AIU provided no attrition studies or estimates of any kind showing margin revenue losses that will occur in the future that suggest that it will be unable to earn its authorized return after the entry of the rate orders in this proceeding or that justify the approval of Rider VBA. In fact, the AG points out, gas usage per customer has been declining for decades, yet AIU has been able to operate under the traditional rate making approach without decoupling. Rejecting Rider VBA will not harm AIU, the AG observes, because when under-recovery does occur the traditional rate case filing process is still available to AIU. Additionally, as noted above, had Rider VBA been in effect from 2004 through 2006, the AG reports that AIU would have collected an additional $38.8 million in gas delivery charges--a cumulative impact of about 7.1% of overall margin revenues in those years. The AG asserts that this would have been an unjust windfall to AIU since the traditional rate case process would have protected AIU's interests.

The AG does not accept AIU's argument that Rider VBA is necessary to remove any disincentive to promote energy efficiency. First, the AG points out that AIU has no history of providing energy efficiency programs or assessing their effect on customer usage. Given this lack of experience, the AG claims that the discussion regarding the alleged disincentive to promote efficiency rings hallow. Second, the AG notes that AIU has no plans for energy efficiency programs beyond the $6.5 million program at issue in Docket No. 08-0104. While AIU asserts that implementation of that program is contingent upon approval of Rider VBA, the AG observes that AIU witness Nelson acknowledges that the Commission can direct AIU to provide the program without Rider

VBA. Third, the AG maintains that Rider VBA may actually discourage customers from increasing the efficiency of their home or business or otherwise reduce their gas usage if their total bill is less dependent on the amount of gas they use. The AG finds AIU's concerns about promoting efficiency particularly specious when one considers that AIU is only seeking decoupling for its gas operations. As Mr. Nelson explains in his response to AG 3.03(c) (MLB), "average electric sales per customer are not declining. Implementing a decoupling mechanism for the electricity business likely would have the effect of providing [AIU] with less revenue over time, and would hasten the need for a subsequent rate case--neither of which is in the interests of [AIU] or its customers." (AG Initial Brief at 43) Thus, the AG concludes that AIU is apparently proposing only gas decoupling in furtherance of the simple financial goal of collecting the maximum revenue between rate cases for the benefit of shareholders--and not due to any altruistic motivation to remove disincentives to promoting energy efficiency.

The AG is also concerned by the additional administrative burdens that approval of Rider VBA will bring. According to the AG, Mr. Brosch and Staff witness Lazare both express concerns about the additional burden that review of three additional riders, and the three annual rates of return reports, will impose on all parties. The AG is not persuaded by AIU's assurances that Rider VBA reconciliations will be simple and uncontroversial.

4. CUB's Position

CUB objects to Rider VBA and relies on Bluefield, Hope, and Finkl in the same manner as the AG. CUB also discusses the arguments of Mr. Brosch. CUB spent additional time, however, discussing BPI II. In BPI II, the Illinois Supreme Court described the rule against single-issue ratemaking as recognizing that the revenue formula is designed to determine the revenue requirement based on the aggregate costs and demand of the utility. Therefore, it would be improper to consider changes to components of the revenue requirement in isolation. Often times a change in one item of the revenue formula is offset by a corresponding change in another component of the formula. To demonstrate this point, CUB states that an increase in depreciation expense attributable to a new plant may be offset by a decrease in the cost of labor due to increased productivity, or by increased demand for electricity. (CUB explains that demand for electricity affects the revenue requirement indirectly. The yearly revenue requirement is divided by the expected demand for electricity to arrive at a per kilowatt-hour ("kWh") rate. If actual demand is more than the estimated demand used in the formula, the utility's revenues increase.) In such a case, CUB states that the revenue requirement would be overstated if rates were increased based solely on the higher depreciation expense without first considering changes to other elements of the revenue formula. Conversely the revenue requirement would be understated if rates were reduced based on the higher demand data without considering the effects of higher expenses. (See BPI II, 146 Ill. 2d at 244-45) The exception permitting recovery of costs outside of the traditional rate-setting process is recovery through riders.

Riders allow a utility to collect revenues associated with a particular cost as it is incurred, without waiting until it files a general rate case to recover such expenses. CUB quickly points out, however, that rider cost recovery is only permitted under limited circumstances, as discussed in Finkl. In this instance, CUB does not believe that it is appropriate to make up for declining revenues, due to decreased gas usage, through a rider. CUB maintains that the proposed Rider VBA is beset by many problems. First, CUB is not convinced that Rider VBA is necessary and notes that AmerenCILCO's gas operation is over-earning despite declining gas usage by customers. CUB adds that fluctuation in earning is common between rate cases and that regulatory lag can even work to a utility's advantage, as it is currently for AmerenCILCO. When earnings are consistently low, CUB asserts that the proper course of action is to file for a rate increase.

CUB is also troubled by AIU witness Cooper's assertion that, rather than reviewing its proposed rates under the standards articulated in Article IX of the Act regarding just and reasonable rates, the Commission should consider that "the real metric for determining whether the tariffs for a utility are just and reasonable is a comparison between the margin revenues generated by these tariffs versus the margin revenue requirement necessary for the utility to have a reasonable opportunity to earn its Commission authorized rate of return." (Ameren Ex. 25.0 at 7) He further argues that the current rate structure has not resulted in earning the respective authorized rates of return. CUB contends that this argument invents a new standard of review – the "margin revenue requirement" – that belies the Act and well-established regulatory policies and principles. CUB believes that it is important to note that, while the Commission always establishes a revenue requirement level, it measures a utility's performance by whether it is meeting its approved rate of return. In fact, CUB continues, the Commission up to this point has never approved a specific level of margin revenues or margin revenue requirement for any gas utility in Illinois.

CUB takes no solace in AIU's willingness to modify Rider VBA so that it more closely resembles the Rider VBA approved in the Docket Nos. 07-0241 and 07-0242 (Cons.). First, CUB argues that calling the rider a "pilot," while simultaneously subjecting all residential customers to potentially higher delivery rates for four years, without substantial review of the program, does nothing to improve it. Second, Mr. Brosch testifies that the annual rate of return filings are no substitute for a correctly structured formula that accounts for all related costs and revenue changes between test years, and are virtually useless in determining whether the riders have caused AIU to earn returns in excess of those authorized by the Commission. Third, since a majority of the delivery system costs are fixed, CUB states that ensuring that only the utility's fixed costs are reflected in the volumetric delivery charge and the associated Rider VBA surcharge will have little to no effect on the level of surcharges imposed under Rider VBA.[10]

[10] The Commission does not mean to slight CUB or diminish the worth of CUB's arguments by not addressing all of CUB's arguments in the Commission's review of CUB's position. Rather, given the similarities between CUB's position and the AG's position, the Commission simply does not believe that repetition of such similar arguments in the Order is warranted.

If it were the Commission's goal to provide utilities with guaranteed cost recovery of its fixed costs, CUB asserts that that policy would more appropriately dictate establishing recovery of all fixed delivery costs through the application of a fixed monthly charge to all affected customers. While CUB acknowledges AIU's suggestion that increasing the monthly customer charge is an alternative to its decoupling proposal, CUB opines that AIU is not seriously proposing to increase the monthly charge. If in fact that is what AIU is proposing, CUB contends that it would likely be rejected outright by this Commission as violating basic ratemaking principles like avoidance of rate shock, maintaining fair and equitable rates, and other cost of service principles. According to CUB, Dr. James Bonbright, an authority on utility ratemaking, has called into the question the propriety of uniform customer charges. CUB quotes Dr. Bonbright as saying, "uniformity of charge per customer (say, $10 per month for any desired quantity of service) has charm in avoiding metering costs. Nevertheless, it is soon rejected because of its utter failure to recognize either cost differences or value-of-service differences between large and small customers." James C. Bonbright et al., "Principles of Public Utility Rates," at 397 (1988).

5. IIEC's Position

From IIEC's perspective, and from a general customer perspective, riders are objectionable and should not be approved when the riders: (a) inappropriately shift operating risk from the utility to customers, as when the costs of service at issue are fully capable of base rate recovery, (b) adjust rates on the basis of only selected costs elements without considering other (possibly offsetting) costs, revenue changes, or other factors that affect the utility's overall profitability (also known as single-issue ratemaking), (c) distort or otherwise compromise the incentives for prudent and efficient utility operation built into the regulatory oversight and ratemaking process, or (d) create cross-subsidies or otherwise result in unfair cost recovery. Because Rider VBA falls short of these criteria, IIEC opposes its implementation.

IIEC asserts that the current regulatory framework provides all interested parties with a fair opportunity to review all items affecting cost-based rates. At the same time, IIEC continues, the existing regulatory framework provides utilities an opportunity to earn a fair return. With Rider VBA, IIEC argues that AIU is inappropriately attempting to shift the risk of non-recovery of anticipated revenues to customers. Currently, AIU's shareholders bear the risk that earnings could be adversely affected between base rate cases due to increases in costs or a reduction in revenue. Conversely, AIU's shareholders benefit if the AIU gas utilities can successfully reduce costs or increase revenues between rate cases. IIEC contends that these facts create a powerful incentive for AIU to operate cost-effectively and to promote economic development efforts in its service areas, increasing revenues, and improving AIU's bottom line between base rate cases. IIEC states that Rider VBA would essentially make AIU indifferent to the impact of fluctuations in sales levels in the service areas, eliminating this incentive.

6. AARP's Position

AARP opposes implementation of Rider VBA. While AIU claims that it "needs" this rider, AARP states that AIU has not provided an analysis of whether overall gas revenues are increasing. As illustrated by AG/CUB witness Brosch, AARP reports that AIU's actual margin revenues have been relatively stable over the past 13 years, in spite of weather fluctuations and in spite of a supposed downward trend in usage. AARP states further that the addition of new customers has historically served to offset most or all of the declining usage per customer noted by AIU. AARP concludes that there is no need for this piecemeal Rider VBA (which would not simultaneously recognize increases in customer numbers) based upon the evidence in the record of this case.

Despite the fact that AIU emphasizes that this rider would be “symmetrical,” AARP argues that it would clearly tip the regulatory scales against consumers and grant an almost guarantee to the utility’s margin revenues. Mr. Brosch argues that specific margin revenues should not be guaranteed. Such guarantees, AARP contends, fundamentally undermine the entire premise of rate of return regulation, forcing consumers to pay the utility a rate of return while shifting the risks of doing business onto those same consumers. AARP reports that calculations show that based on historical records, AIU would have collected an additional $38.8 million in gas delivery charges from consumers from 2004 through 2006, a cumulative impact of 7.1% of overall margin revenues over that period of time.

Not only is the Rider VBA a piecemeal approach as to the rate of return formula for ratemaking, AARP notes that AIU's proposal is piecemeal as to its overall operations in that it is being proposed for its gas operations, but not its electric operations. AARP relates that the reason given by AIU was that electric sales per customer are not currently declining, and thus an electric decoupling rider would likely produce less revenue for AIU. AARP avers that such a response clarifies that the utility’s goal is actually revenue enhancement, not the removal of any “disincentive” regarding energy efficiency programs.

Furthermore, AARP suggests that the Commission should not embark upon another new decoupling pilot program, at least not until the People’s Gas decoupling rider (just approved on February 5, 2008) is allowed to run its course and is then evaluated. Launching straight into another similar “pilot” may satisfy some sense of uniformity between regulated utilities, but according to AARP it would be to the detriment of yet another group of consumers without any proof that this specific utility truly “needs” such a mechanism. If a pilot program is to mean anything, AARP asserts that it should at least be used as an experiment to test the necessity for such extraordinary mechanisms and to analyze how much more ratepayers actually wind up paying.

Moreover, AARP continues, the Commission may learn from the People’s Gas pilot what unintended customer reactions may develop when the benefits of

conservation are taken away from natural gas consumers. AIU discusses how Rider VBA would reduce its “disincentive” to support energy efficiency efforts, but according to AARP it did not discuss what impact the Rider VBA would have on customer behavior. Mr. Brosch concludes that Rider VBA will likely diminish the incentive for consumers to lower their thermostats, invest in energy efficient appliances and weatherization, or to participate in the very programs that AIU claims it wants to provide. AARP believes that many of its members will likely feel discouraged from engaging in conservation, knowing that any overall gains in conservation would be quickly diminished by the operation of this rider.

7. Commission Conclusion

Rider VBA as proposed only applies to GDS-1 and GDS-2 customers of each gas utility. The Commission therefore understands that AIU is most concerned about declining gas usage by these two customer classes. Of the fixed delivery service costs recovered through customer charges, volumetric delivery charges, and demand charges, AIU indicates that approximately 43% of its fixed delivery service cost is recovered based on the volume of gas used by customers. The vast majority of the remaining fixed delivery service costs are recovered through the monthly customer charge. Whenever gas usage by these two classes falls below the test year usage level, AIU's ability to recover that portion of its fixed costs collected through the volumetric charge is impaired.

Why AIU would want to recover as much of its authorized revenue requirement as possible is clear. AIU has proposed Rider VBA as a means of recovering its fixed costs through the continued use of volumetric charges. In Docket Nos. 07-0241 and 07-0242 (Cons.), the Commission recently approved the use of a similar rider for Peoples and North Shore as a four year pilot program. From this decision, it is evident that the Commission is willing to consider alternatives to the traditional method of recovering a portion of fixed costs through the volume based portion of the bill.

The Commission is fully aware that its decision in Docket Nos. 07-0241 and 07-0242 (Cons.) was controversial. Many of the same parties involved in that proceeding have participated in this proceeding and made many of the same arguments regarding AIU's proposed Rider VBA. The Commission acknowledges those concerns and reevaluated them in this proceeding.

What carries the most weight is the argument that the Peoples/North Shore Rider VBA was approved as a pilot program, and it would make little sense to expand the pilot program to AIU without having any of the results from Peoples' and North Shore's experience. AIU's proposed Rider VBA is very similar, if not substantively identical, to the Rider VBA approved in Docket Nos. 07-0241 and 07-0242 (Cons.). If there are unknown flaws in the approved rider, it is likely that the same flaws exist in AIU's proposed rider. Allowing Peoples and North Shore to implement this controversial rider under the pilot program, and hopefully identify any problems with the rider, before expanding it to a significant number of additional customers seems more prudent than

expanding the rider now without the benefit of any significant experience with the rider. Furthermore, using an alternative to Rider VBA that would still provide AIU a better opportunity to recover its fixed costs will supply the Commission more information with which to evaluate ways to recover a utility's fixed costs.

An alternative to Rider VBA that would still promote fixed cost recovery by the utility is recovery of a greater portion of fixed delivery costs through the fixed monthly charge to all affected customers. AIU makes this suggestion and notes that under this method, utilities could not over- or under-recover their Commission-approved base rate revenue requirement with changes in sales. AIU adds that this alternative would also send proper price signals to customers. The Commission concurs with these statements and notes further that this alternative arguably decreases any disincentive AIU may perceive to implementing gas efficiency programs. Specifically, AIU has pending before the Commission in Docket No. 08-0104 a gas energy efficiency plan which it indicates is contingent upon approval of Rider VBA. The Commission anticipates that in light of the end result under the conclusion on this issue, AIU will not shy away from efforts to decrease gas consumption by its customers.

Accordingly, the Commission concludes that it will not adopt AIU's Rider VBA, but that it will direct AIU to increase its monthly customer charge for the GDS-1 and GDS-2 classes to recover more of its fixed delivery services costs. AIU proposes a monthly charge of $15.00 for all GDS-1 customers. AmerenCILCO's current monthly residential customer charge is $11.80. The current monthly charge for AmerenCIPS Metro-East residential customers is $15.00. For all other AmerenCIPS residential customers, the monthly charge is currently $10.50. The standard monthly charge for AmerenIP residential customers is currently $10.27, while the non-standard monthly charge is $32.46. The current and proposed monthly customer charges for small general service under GDS-2 vary depending on meter facilities and whether a customer is a sales or transportation customer. Ameren Ex. 12.2G identifies the current and proposed monthly charges. As mentioned earlier, AIU's proposed monthly customer charges for GDS-1 and GDS-2 customers would recover nearly 57% of AIU's proposed fixed delivery services costs. AIU should modify its monthly customer charges for these classes to recover 80% of the fixed delivery services costs approved in this proceeding. With regard to varying charges for the GDS-2 class, the increases should be proportionate to existing rates. The Commission anticipates that this method of recovering fixed delivery costs will be simpler and easier for customers to understand than Rider VBA.

The Commission does not at this time approve recovery of all fixed costs in the monthly charges for two reasons. First, it is expected that leaving a portion of fixed costs to be recovered through the volumetric rate will encourage AIU to seek ways to improve efficiency and otherwise cut costs. Second, as the number of AIU's customers grows, AIU should experience growing revenue. If all of its fixed costs were recovered through the monthly charge, AIU may arguably over-recover its fixed costs through the monthly charge.

In order to gain sufficient experience to evaluate this method of recovering fixed delivery costs, the Commission anticipates that the approved ratio of fixed costs recovered from the customer charge and the volumetric rate must remain in place until at least December 31, 2012. AIU may propose revisions to this ratio in its next rate case or rate design case thereafter. By this time the Commission should also have the benefit of Peoples' and North Shore's experience with Rider VBA.

In their respective Brief on Exceptions, Staff and the AG complain that increasing the monthly customer charge to recover a greater portion of fixed costs will be detrimental to GDS-1 and GDS-2 customers. While the Commission acknowledges that the monthly charges will increase and such increases may be more apparent on bills than changes to volumetric rates, the fact remains that the volumetric rates will decrease by a corresponding amount. Therefore, on average, there should be no overall adverse revenue impact on customers resulting from recovering a greater portion of fixed costs through the monthly customer charge than a volume based rate. So that customers realize this, however, the Commission directs AIU to include in at least one bill insert soon after entry of this Order a statement explaining that a greater portion of the fixed costs of delivering gas will be recovered through the monthly customer charge and that the amount of fixed costs recovered through the volumetric charge has been correspondingly reduced.

B. Rider QIP

1. AIU's Position

AIU states that it intends to improve infrastructure performance (i.e., system reliability) by increasing both O&M expenditures and capital expenditures. Specifically, AIU states that it plans to spend $909 million in electric capital expenditures for the 2007-2009 time period. Over two-thirds of these capital expenditures, AIU continues, will be dedicated to infrastructure improvement.

Certain factors, however, limit its ability to make infrastructure investments, according to AIU. Obviously, access to capital funds is necessary. AIU explains that some of those funds are provided by cash flow from operations, based on the revenue requirement and rate base from the most recent rate case. AIU claims, however, that cash flow from operations will be insufficient to make such improvements based on a static rate base and revenue requirement. AIU says that it will therefore have to go to the capital markets to secure funds for infrastructure investments. Without a ready source of rate recovery for capital investments, AIU states further that there is no way to pay interest to debt providers or to pay dividends and provide a return to equity investors. In other words, AIU is asserting that significant and continued investments in infrastructure can only be made, and sustained, when a fair return on and a return of investment are received on a timely basis. AIU adds that capital investments made between rate cases cause earnings and return on equity to fall, further impairing the ability to raise capital.

AIU indicates that it can address the regulatory lag issue in one of two ways: (1) delay projects so they are timed with a rate case; or (2) create a rate mechanism to reflect such incremental projects in rates on an on-going basis, subject to Commission review and reconciliation. AIU proposes the incremental approach, which includes the capital costs of projects in rates as they are completed and placed into service. Thus, AIU is seeking approval of Rider QIP to provide timely recovery of capital costs for certain distribution plant investments, thereby allowing continued investment in infrastructure. The rider would recover costs associated with a defined set of plant additions beginning after December 31, 2007.

AIU proposes to limit the project expenses recoverable under Rider QIP. For example, capitalized expenditures related to existing distribution plant would qualify for the rider. Plant additions associated with new customers would not qualify for the rider, because those projects would produce additional revenue. AIU explains that these criteria are consistent with its goal to make its system stronger and more durable because capital expenditures on existing distribution plant are made to either enhance the system or replace existing plant to increase system reliability.

Customers will benefit from the projects eligible for Rider QIP cost recovery, according to AIU, through enhanced system reliability, including fewer and shorter outages than would otherwise be experienced. AIU indicates that these are not the only types of system improvements that could benefit customers. Additionally, AIU states that investments may be required as a result of the Commission-mandated audit of AIU's delivery systems and storm preparedness when recommendations are received in 2008. AIU states further that it is studying “smart metering” and “smart grid” technologies that may provide future benefits to customers.

The concepts of smart metering and smart grid are currently being defined as the transformation of the electric delivery system of the 20th century into the delivery system of the 21st century. Many envision the system of the future as one that will continue to use the same types of equipment that are used today for electric delivery – e.g., power lines, substations, and transformers − but also picture it as a fully automated delivery network that monitors and controls every customer and node, ensuring a more reliable flow of electricity and a two-way flow information between the power plant and the appliance, and all points in between. AIU reports that smart metering, in addition to measuring electricity usage and voltage on a real-time basis, allows for two-way communication and provides the utility with new capabilities for operating and managing the delivery system. Smart metering coupled with communication functionality could enable utility customers to see and understand how and when they consume electricity. This in turn, AIU continues, will provide consumers the ability to manage their consumption of energy and take advantage of time-based rates − shifting usage of energy from peak periods or high-cost periods, taking steps to conserve electricity, and reducing their energy costs.

Furthermore, while smart meters will satisfy traditional metering needs for the utility − the measuring of the consumption of energy for system design and billing

purposes - they could also serve as portals into the consumers' homes or businesses. AIU contends that smart meters will add additional value for both the consumer and the utility when the information they provide and the communication capabilities are used to enable distribution automation, demand response, load management, and real-time pricing. As the electric delivery system or grid continues to evolve, AIU submits that smart meters could become an integral part of an array of intelligent electronic devices that will make up what is conceptually referred to now as the "smart grid."

AIU indicates that it has already invested in advanced meter reading ("AMR") technologies--beginning a 4-year deployment of automated meter reading technology in May, 2006. AIU states that its commitment to the deployment of AMR technologies has required and will continue to require a significant investment in new and retrofitted meters, data gathering equipment, and telecommunications and information processing systems. Benefits that AIU anticipates deriving from AMR technologies include, but are not limited to, reduced meter reading costs, improved reliability, and enhanced restoration efforts through remote detection of customer outages.

In addition to implementing some level of AMR technologies, AIU states that it intends to begin studying the costs, benefits, and steps that would be necessary to implement smart meters and the smart grid for residential and small commercial customers. As of this year, AIU has begun assessing and comparing the current state of the energy infrastructure in the region to future scenarios involving smart grid technologies. AIU also plans to identify additional programs and potential tariff offerings that would allow customers to begin to take advantage of some of the benefits of smart metering. AIU argues that Rider QIP would facilitate investments in smart metering and a smart grid.

In an effort to address some of the concerns expressed by Staff and interveners, AIU modified its original Rider QIP proposal. In particular, AIU proposes to change the definition of Rider QIP projects to include only those associated with system modernization or service reliability enhancements. Further, before any project costs can be recovered through Rider QIP, AIU says that it will file a cost/benefit analysis. AIU has committed to make any such filing on or before April 1st of each applicable calendar year, providing nine months to review and approve any Rider QIP charges prior to the subsequent January 1 effective date. Parties could intervene in a Commission proceeding initiated after the filing of a cost/benefit analysis and express their views on which projects or initiatives, if any, should qualify for rider recovery. The Commission would then decide which projects or initiatives qualify.

AIU believes that the cost/benefit analysis should also address the concerns of the AG, IIEC, and AARP regarding the shifting of risk to customers and loss of incentives for the utility to behave in a prudent manner if Rider QIP is approved. AIU argues that these claims should be disregarded since passing a cost/benefit test at the Commission must precede timely recovery of the costs associated with a project. This process, AIU continues, results in maintaining the status quo, especially in times of escalating costs. Moreover, AIU states that each utility is still bound thereafter to justify

the prudence of the expenditures actually made in an annual prudence review. AIU asserts that it has every reason to behave in a manner that ensures that the Commission will not disallow costs. To mitigate the impact of reviewing Rider QIP on the Commission's resources, AIU offers to pay a combined $100,000 annual filing fee. Concerning operational risk, AIU insists that Rider QIP does not shift operating risk; instead, it neutralizes operating risk.

AIU acknowledges AG/CUB witness Brosch's concern that Rider QIP does not take into consideration updates to the depreciation reserve, deferred taxes, and O&M expense. He also states that Rider QIP does not consider potential savings related to new plant investment. To address such concerns, AIU will be filing an annual rate of return report along with each Rider QIP filing to the extent that the subject costs are being recovered through the rider. The annual rate of return report will contain updated depreciation reserves, deferred taxes, and O&M expenses, which the Commission may consider when evaluating whether or not to allow Rider QIP recovery. AIU indicates that if the Commission determines that AIU is exceeding the allowed return, or if it believes potential savings, if any, from a project or initiative will cause AIU to exceed the allowed return, the Commission can choose not to allow Rider QIP recovery. Additionally, AIU agrees that Rider QIP can stand as a pilot program through and including December 31, 2012. Thereafter, AIU would need to re-file Rider QIP or some variation of the rider if they seek to continue to recover costs in such a manner.

Staff witness Lazare's suggestion that AIU use a future test year to recover anticipated project costs does not sway AIU. AIU claims that a future test year does not adequately address its concerns regarding regulatory uncertainty. AIU states further that a future test year is difficult to prepare and both costly and burdensome.

AIU does not oppose Staff witness Stoller's recommendation that the Commission take up this type of rider in a broader proceeding, outside of a rate case. AIU states that the Commission should give serious consideration to initiating a proceeding to examine what it claims are "evolving" service quality standards. But at the present, AIU is willing to make Rider QIP a pilot program now, with a definite expiration date. AIU believes that the expiration date should address Mr. Stoller's concern since it allows the Commission to consider a permanent program or rule in a broader proceeding, while allowing Rider QIP to go into effect in the meantime.

In response to Mr. Brosch and IIEC witness Stephens arguing that the infrastructure project costs are predictable and controllable and therefore do not warrant rider treatment, AIU contends that there needs to be recognition of changing times and public policy. AIU points out that in the Rate Relief Bill (Public Act 95-0481) passed last summer, there was recognition that the State, through electric utilities, would pursue energy efficiency and demand response programs and technologies. As part of that policy, the General Assembly authorized the use of an automatic adjustment clause rider to be approved by the Commission to recover the subject costs. Similarly, AIU continues, the General Assembly in late 2006 passed legislation mandating residential real time pricing. A rider was also authorized that would allow the utility to recover its

costs. AIU recognizes that these are legislatively mandated riders, but reasons that the Commission is an extension of the General Assembly and is fully capable of promoting public policies as well.

Mr. Stephens speaks of the opportunity for the utility to enhance cost recovery in between rate cases, as does AARP witness Smith. AIU contends that a utility may have been more opportunistic in between rate cases when it owned generation, when increased load growth, off-system sales, or hot summers would have increased revenue. Today, however, AIU maintains that a utility without generation does not experience the same benefits as a generation-owning utility that would allow it to absorb the lag associated with significant delivery investment without adversely affecting earnings. Similarly, AIU does not accept Mr. Smith's claim of increased revenues between rate cases since AIU contends that costs will continue to escalate.

2. Staff's Position

Staff recommends that the Commission reject AIU's proposed Rider QIP as it represents a deviation from traditional regulation that would add significant costs for ratepayers and to the regulatory process without providing any tangible benefits. Staff acknowledges that AIU anticipates capital expenditures of $909 million for its electric systems over the 2007-2009 time period. Staff also understands that AIU is concerned about the regulatory lag associated with recovering these costs through the traditional rate case process. AIU's arguments in support of Rider QIP, however, do not sway Staff. Staff points out that rider recovery should be reserved for highly volatile, uncontrollable, and/or unpredictable costs--a standard which even AIU recognizes. Yet none of AIU's arguments, Staff notes, suggest that these costs are volatile, uncontrollable, or unpredictable.

If AIU expects to incur significant costs in the future, Staff suggests that a more reasonable approach would be to file a rate case based on a future test year. A future test year could be designed to recover future investments that may not be appropriately captured in an historical test year. In response to AIU's concerns that a future test year is difficult to prepare, costly, burdensome, and rarely used, Staff identifies three pending rate cases using future test years: Docket No. 07-0507 (IAWC), Docket Nos. 07-0620, 07-0621, and 08-0067 (Cons.) (Aqua), and Docket No. 08-0363 (Nicor). If smaller water utilities have the capability of employing future test years, it is not clear to Staff why AIU should find a future test year prohibitively difficult to prepare or too costly and burdensome to implement. Staff asserts that AIU's concerns about regulatory uncertainty should be dismissed as well. Staff avers that the requirement that reasonable justification for system upgrades be provided in the ratemaking process is essential to protect the interests of shareholders and ratepayers alike. Furthermore, Staff states that AIU can reduce regulatory uncertainty by providing strong support for the proposed investments.

Staff also understands that AIU is considering smart metering and smart grid technologies. The problem that Staff has with AIU's interest in such technology is that it

is not clear whether Rider QIP is being proposed to make the system more reliable, to transform it technologically, or to do both. The fact that the language of the rider and AIU witness Nelson's discussion of smart meters and the smart grid are both open-ended raises a concern for Staff that approval of Rider QIP will give AIU a license to transform the distribution system beyond the ability of ratepayers to pay the corresponding costs. As the events of 2007 clearly indicate, the concerns of ratepayers appear to be with the levels of their electric bills.

In response to Mr. Nelson's claim that customers would not pay any more for reliable service under Rider QIP, Staff argues that the reality would be the opposite. In between rate cases, Staff asserts that AIU would be able collect additional amounts from customers, which contrasts with traditional ratemaking where utilities can not pass along additional costs once rates are set. Moreover, Staff contends that AIU fails to provide adequate reason why ratepayers should be asked to pay an extraordinary price for what appears to be ordinary electric service. Mr. Nelson testifies that customers will benefit from Rider QIP "through enhanced system reliability, including fewer and shorter outages than would otherwise be experienced." (AmerenCILCO Ex. 2.0E at 30; AmerenCIPS Ex. 2.0E at 30; AmerenIP Ex. 2.0E at 30) Staff maintains that this higher quality of service is something ratepayers should normally expect from AIU--it should not be something for which they have to pay extra. Furthermore, Staff relates that AIU has a statutory obligation to provide safe and reliable service at minimum cost. Staff argues that AIU should not receive an additional financial reward, as would be provided by Rider QIP, to fulfill this obligation to maintain a safe and reliable system.

AIU examined two other riders when drafting its proposed Rider QIP. One is the Qualifying Infrastructure Plant Surcharge Rider of IAWC. The second is the Infrastructure Cost Recovery Rider proposed in the recent North Shore/Peoples rate case. AIU argues that following a similar approach to these riders supports the Commission's goal of promoting "uniformity of common riders." The similarity of Rider QIP to the North Shore/Peoples proposed rider, however, causes Staff to urge caution since the Commission rejected the North Shore/Peoples proposed rider. (See Docket Nos. 07-0241/07-0242 (Cons.), Order at 162) Staff argues that AIU has failed to provide the full range of information discussed by the Commission and, therefore, AIU's proposed Rider QIP falls short of the standard set in Docket Nos. 07-0241/07-0242 (Cons.).

Staff recommends further that if the methodology for recovering investments in infrastructure is to be changed, that change should not be made in this rate case. Staff witness Stoller argues that the facts and policies involved should be thoroughly reviewed in a focused and separate proceeding. Mr. Stoller suggests that the Commission give serious consideration to initiating a proceeding to examine "evolving" utility service quality standards, and possibly to changing the provisions of the Commission's rules at 83 Ill. Adm. Code 410, "Standards of Service for Electric Utilities and Alternative Retail Electric Suppliers" ("Part 410"), and 83 Ill. Adm. Code 411, "Electric Reliability" ("Part 411"), consistent with modifications, if any, that need to be made to those rules regarding electric distribution system investment.

Mr. Stoller discusses AIU's perception of its inability to earn a fair return on investment in the maintenance and modernization of utility distribution systems. While utilities earn a return of and on their investment in their distribution systems, he notes that Mr. Nelson questions whether utilities earn a sufficient return on their investment to warrant investment that will improve their systems. Mr. Stoller states that the broader question may be whether the regulatory process effectively addresses distribution system reliability and whether changes are warranted to improve utility distribution systems. Answers to those broad policy questions would affect not only AIU, Mr. Stoller observes, but all utilities in Illinois.

Concerning the specifics of Rider QIP, Mr. Stoller does not offer a specific definition of what constitutes system modernization, but indicated that those are generally the type of projects to which he believed any expedited cost recovery mechanism such as Rider QIP should apply in its potentially broadest application. Mr. Stoller also recommends completely eliminating language that would make Rider QIP applicable to "service reliability enhancements," saying that he believes that that definition is far too broad. Additionally, Mr. Stoller testifies that he does not believe that all utility work on a distribution system that could be claimed, or even agreed, to enhance service reliability should necessarily be entitled to expedited cost recovery. Such work could easily include such traditional projects as replacing old and rotted poles or simply replacing old distribution lines. Mr. Stoller acknowledges that while he is well aware that those projects can be valuable in maintaining and enhancing reliability, his position is that the Commission needs to be far more careful in defining what utility projects are entitled to expedited cost recovery treatment than to simply include in that category all projects that can be claimed or even demonstrated to enhance reliability.

If Rider QIP is implemented, Mr. Stoller agrees that a periodic filing and approval proceeding process would be a suitable approach. He is not prepared to agree that going through a process each year would be necessary or advisable, but states that having a known and predictable process in place would be beneficial for planning purposes for any party that might be interested in participating. He submits that perhaps the process should only occur at two-year intervals and perhaps the Commission approval process should be longer than the nine-month process that Mr. Nelson recommends. Mr. Stoller does not claim to have the answers to such questions, but suggests that they are questions that could be resolved in the collaborative process he recommends. Staff believes that Mr. Nelson's offer of payment to accompany such a filing is neither appropriate nor authorized by statute. Staff is concerned that the payment would create the appearance of impropriety.

If the Commission opts to follow his recommendation of a collaborative process, Mr. Stoller states that the participants should consider and make recommendations to the Commission regarding (1) the appropriate technological route or routes to follow for smart grid or other utility plant investment, (2) how to define which utility projects should be eligible for Rider QIP, or some other form of expedited cost recovery consideration, and (3) the process through which projects that might be considered for expedited cost

recovery treatment should be proposed, evaluated, and approved and the time limitations for doing so. Mr. Stoller suggests that the collaborative process move on an expedited basis, but should not be time-limited in advance. He explains that neither the Commission nor any potential party knows at this time just how much information the parties might find it necessary to examine and how much time the parties may need to make recommendations. Only when the collaborative process is completed, and the Commission adopts the recommendations that it finds appropriate, does Mr. Stoller believe that Illinois utilities should file for Commission consideration a Rider QIP-type tariff, or if the Rider QIP tariff has already been approved in this proceeding, begin proposing projects for expedited cost recovery consideration and treatment.

3. AG's Position

The AG opposes implementation of Rider QIP. Some of the AG's general arguments regarding the appropriateness of riders in the above discussion of Rider VBA are also applicable to Rider QIP. Generally, with regard to Rider QIP, the AG contends that AIU has not provided any evidence of financial need for a rider for future distribution plant investments. In addition, the AG finds that the proposed Rider QIP is conceptually and mechanically flawed, would add considerable administrative burdens for Staff, interveners, and the Commission, and approval of the rider would conflict with the parameters of utility ratemaking outlined both in the Act and by Illinois courts.

a. Rider Treatment Eligibility

AG/CUB witness Brosch describes the general criteria employed by regulators to evaluate riders that are proposed as exceptions to traditional test year period regulation. The AG argues that Rider QIP fails every one of the general criteria that are routinely relied upon by regulators to evaluate rider proposals and highlighted by Illinois courts as appropriate for rider recovery. The AG asserts that the continuing investments that AIU makes in electric distribution are clearly not “highly volatile or unpredictable,” as evidenced by the fact that AIU management is able to control and budget such costs and make decisions regarding prioritization of capital spending. On the contrary, the AG observes, continuing plant investments are subject to rigorous investment screening, as discussed by AIU witness Getz, and only very gradually contribute to changes in rate base.

Likewise, the AG contends that AIU's historical and projected investment levels in electric distribution plant do not indicate cost volatility or any apparent inability to manage and control spending. The AG relates that past and future *budgeted* electric distribution plant spending has been and is expected to remain relatively stable, with an average expenditure level for the period of 2004 through 2011 of $157 million. Minimum spending of $121 million (23% less) occurred in 2005 and maximum planned spending of $181 million (15% more) is budgeted in 2008. AIU’s historical *actual* capital expenditure levels have been similarly non-volatile. For the years 2004 through 2006, the AG reports that actual annual Gross Construction Expenditures, as shown on page 5 of AIU's First Revised Schedule WPD-7, have ranged from $54 to $57 million per year

for AmerenCILCO, $45 to $82 million for AmerenCIPS, and $134 to $177 million for AmerenIP.

Moreover, the AG asserts that new electric distribution plant investments can create productivity improvements and reductions in expenses that help AIU mitigate the costs of increasing capital investments. Significant amounts of electric distribution spending is targeted for reliability projects that are responsive to problem areas prone to excessive outages – and when older, unreliable plant is replaced, the AG states that savings are expected because of reduced outage restoration effort and expense in those areas. There are also opportunities, the AG adds, to deploy new technologies within the electric distribution network that are intended to capture expense savings. The AG points to the previously discussed four-year AMR project that began in 2006. AIU plans to expand AMR to an additional 1.1 million meters in Illinois by the end of 2009. The AG states that the primary reasons for investing in this large project are savings in operating cost and improvements in customer service enabled by AMR technology. The AG notes that AIU elected to deploy AMR under traditional regulation and without any extraordinary Rider QIP ratemaking treatment.

The amount of money to be generated by Rider QIP likewise is not significant enough in relation to the total revenue requirement to justify rider treatment, according to the AG. In its response to Data Request No. AG-1.30, AIU provides illustrative calculations of the quarterly Rider QIP calculations that would apply to its "forecasted 2007 distribution plant additions" totaling $36.1 million. At this assumed spending level, the AG states that Rider QIP incremental quarterly and annual revenues would be $200,000 and would steadily ramp upward between rate cases as more plant is added each quarter. Extrapolating projected distribution plant additions at this pace, the AG continues, would suggest estimated annual revenue impacts of approximately $2.0 million in year one, $5.4 million in year two, and $9.2 million in year three (assuming no rate cases). While AIU has not justified its financial need for any of this incremental revenue, the AG goes on to say that by year three the incremental revenue of $9.2 million and corresponding incremental income after taxes of about $5.5 million is clearly not large in relation to total proposed electric utility operating income for the utilities of $189.3 million. Because the revenue requirement impact translates into only about 16% of the dollar amount of incremental capital spending, the AG asserts that AIU would need to vastly expand its planned electric distribution capital spending to experience the large or potentially volatile revenue requirement impacts that are normally required for special rider approval.

Furthermore, the AG insists that there is no evidence that traditional regulation has precluded AIU from taking advantage of cost effective opportunities to make or accelerate capital expenditures. The AG observes that to date, AIU has successfully modernized its network and, generally speaking, maintained reliability over the years, without benefit of an automatic rider recovery mechanism for distribution system modernization projects. AIU has been investing hundreds of millions of dollars in new plant every year in the normal course of business. Additionally, the AG notes that AIU fails to identify any particular investment project required to meet its service obligations

to its customers that it could not make because of the absence of a mechanism like Rider QIP. Also of importance, the AG adds, is that all of those expenditures historically made by AIU were incurred without advanced Commission approval.

b. AIU's Current Budget Process

The AG reports that AMS' Managing Supervisor of Business Performance, Mr. Getz, oversees the capital budget process and testifies that he was unaware of any specific projects that AIU was unable to finance through internally generated funds and the capital markets that would be appropriate for Rider QIP inclusion. Similarly, Mr. Getz confirms that AIU has not specifically identified any projects that will be proposed in the rider. The AG professes amazement that Mr. Getz is unaware at this point as to how the Rider QIP process is to work. The AG is also concerned by Mr. Getz's testimony that Rider QIP would simply provide additional funds for the financing of capital projects "that may not make the cut today." (Tr. at 606) This raises a question for the AG of whether the preferential ratemaking under Rider QIP may induce AIU to invest in certain capital projects that are otherwise only marginally justified under AIU's economic analyses. (See generally Tr. at 600-606)

If Rider QIP is adopted, Mr. Brosch is concerned that the incentive for utility management to act prudently with expenditures between rate cases will be lost, or at least diminished. According to the AG, Mr. Getz confirms the efficiency of AIU's existing budget process under traditional regulation. Mr. Getz testifies that the existing method begins in April and typically ends in December. According to Mr. Getz, and AG Cross Exhibit 6, capital budgets are created for each of the three utilities based on approximately 20 internally defined budget groups, such as line transformers, meters, and distribution substations. Blanket or standing work orders are budgeted in April and reviewed by a Central Review Committee ("CRC") of managers to see if they seem reasonable in terms of the dollars that are identified and the rationale provided. The business performance supervisor reviews these in May. The process is designed, according to Mr. Getz, to ensure that allocated dollars are efficiently earmarked to ensure the availability of dollars for specific projects. Mr. Getz states that some projects are sent back to individual budget groups as rejected for further refinement. He adds that revisions are sometimes made to estimates. (See generally Tr. at 607-612)

The AG continues to describe AIU's budgeting process by relating that Mr. Getz testifies that engineers submit specific projects for consideration into the Integrated Spending Prioritization ("ISP") Tool during May of each year. These projects are typically valued at $100,000 or more. The ISP Tool is an "optimization program" with weightings based on safety, System Average Interruption Frequency Index reliability, and other factors that are applied to each specific project to rank the projects. According to Mr. Getz, the CRC meets in June to review specific project prioritization through the ISP Tool as well as budgeting personnel prioritization based on preliminary capital targets from the Treasurer's organization. Hard capital targets are established in August and any adjustments that need to be made are done so by the CRC. At this point, Mr. Getz explains, AIU is trying to "fine tune" the capital budget, with another

review of the budget numbers developed in June. The recommended budget is then forwarded to the AIU President and Vice Presidents for review. (See generally AG Cross Exhibit 6 and Tr. at 613-616)

Mr. Getz confirms that this capital budget process is designed to include checks and balances that contribute to the provision of reliable service while maintaining AIU's shareholders' and ratepayers' financial interests. In addition, he verifies that this budget process helps ensure that AIU invests in capital projects that are needed for both reliability and to meet customer demand for services. Mr. Getz asserts that the existing capital budget process "does a good job of prioritizing" capital spending, and that these checks and balances have helped ensure that AIU's electric rates are least cost from the customers' perspective. (Tr. at 618)

The AG finds it ironic that, if approved, Rider QIP would reduce the normal regulatory lag incentive that a utility faces between rate cases, and provided evidence of such incentive in the above-described AIU capital budget process. Such a reduction serves to encourage careful management and optimization of capital expenditures. The AG is concerned that Rider QIP would provide expedited piecemeal rate increases for incremental qualifying capital investment between rate case test years, and diminish management's obligation to carefully manage and optimize capital expenditure levels. When asked during cross-examination whether Rider QIP projects would run through the existing capital budget process, the AG reports that Mr. Getz testified that he was "not sure what the plan is going forward, or, you know, what the process is envisioned to be." (Tr. at 598)

The AG further argues that there is no evidence that AIU faces a financing problem that makes Rider QIP necessary. The AG notes AIU witness Nelson's testimony that, "(w)ithout a ready source of rate recovery for capital investments, there is no way to pay interest to debt providers or to pay dividends and provide a return to equity investors." (AmerenCILCO Ex. 2.0E at 28) The AG considers it significant that Mr. Nelson does not state that AIU is unable or unwilling to invest in new plant. The AG asserts, that AIU enjoys considerable cash flow from its regulated operations in Illinois and expects to continue to be able to finance most of its planned construction expenditures from internally generated cash flow from operations. In its response to Data Request No. AG (MLB) 3.09, AIU provided its most recent confidential financial projections of income, balances sheets, and cash flows for the years 2008-2010 assuming no rate relief is granted in the pending rate cases. Mr. Brosch finds it instructive that AIU expects to generate virtually all of the capital needed to finance planned construction activities in Illinois from the cash flows produced by consolidated utility operations (rather than capital markets), as shown in the proprietary table at page 61 of his direct testimony. From this information, the AG contends that it is clear that Rider QIP is not needed by AIU to provide access to capital markets on reasonable terms, because traditional ratemaking and the strong cash flows arising from operating income and the collection of depreciation for existing plant service generates most or all of the cash required by AIU for new investment in Illinois.

c. Ambiguity Concerns

Under Rider QIP, capitalized expenditures related to existing distribution plant, but not those additions associated with new customers, would qualify for the rider. In addition, the rider lists nine accounts for which cost recovery under Rider QIP is possible. According to Mr. Nelson, Rider QIP projects include only those "associated with system modernization or service reliability enhancement." The AG, however, is still concerned that the terms of Rider QIP may permit AIU to recover nearly any plant investment under Rider QIP. For example, the AG notes that under cross-examination, AIU witness Cooper acknowledged that the majority of capital investment projects for electric delivery service would be listed under these nine accounts. (Tr. at 514)

Additionally, Mr. Brosch notes that it is often difficult to distinguish whether specific electric distribution projects are partially driven by growth in customer demand. The AG argues that new investments made to extend distribution lines and to connect new customers with meters and services should clearly be excluded from Rider QIP because AIU desires retention of new business margin revenue for its shareholders between test years. Mr. Brosch adds that construction costs incurred to replace existing facilities with larger and newer facilities may not be solely related to either growth or reliability, but instead be driven by a combined need to replace obsolete or unreliable equipment as well as a need to expand capacity of existing circuits. When asked in Data Request No. AG 1.39(b) to clarify how Rider QIP would apply to “capital expenditures that are made to increase the capacity of existing primary distribution feeders to accommodate growth in demand caused by new customers in the area served,” the AG relates that AIU responded, “If the reason for the distribution feeder project was triggered *solely* by the demand growth of new customers added subsequent to the test year period for the most recent rate case, then none of the project capital expenditures would qualify for QIP treatment” (emphasis added). The AG interprets this to mean that any project driven jointly to meet demand growth and address reliability concerns would fully qualify for Rider QIP inclusion, under this liberal interpretation of the project inclusion criteria AIU is proposing for the rider.

With regard to the phrase "system modernization or service reliability enhancement," Mr. Brosch notes that “system modernization” is a vague term that is not defined anywhere in AIU's rebuttal testimony and could be construed to include virtually any project that employs currently available materials or technologies to replace older, existing plant assets. The same is true, he continues, for the new “service reliability enhancement” classification proposal, because the replacement of nearly any older or deteriorated plant asset with newer materials or equipment could reduce the possibility of failure and customer outage and thereby enhance reliability.

With respect to the proposed filing of cost/benefit analyses, the AG is troubled by the fact that no details are provided to explain what methodologies or cost/benefit metrics are to be employed or what level of detail or accuracy will be contained in such “analyses.” Given the vague definition of types of modernization or reliability projects that may be proposed as well as the complete lack of details regarding how the

promised cost/benefit analyses will be performed or measured, it is impossible for the AG to tell how much or little detailed information would be contained in the proposed annual filings and related analyses. The AG believes that it is conceivable that each annual filing by AIU may contain a large number of individual capital projects, each with some level of supporting economic analysis that requires detailed discovery and study by Staff and any concerned interveners before any informed Commission deliberation or approval of charges to customers could occur. In apparent recognition of the regulatory burden these filings would represent, the AG notes that AIU offered to contribute $100,000 to the Commission to fund Staff (but not interveners') review of these filings. The AG adds that it is unclear whether AIU intends to try to pass this $100,000 through to customers.

When asked by the AG in discovery to provide a specimen copy of a cost/benefit analysis, AIU responded by stating, "The form of the cost/benefit analysis has not yet been drafted; however, AIU intend that it be similar to that which the Commission described in its Order in the recent Peoples/North Shore case." The AG finds the reference to the Commission's Order in Docket Nos. 07-0241/07-0242 (Cons.) unhelpful since the Commission did not prescribe any form of cost/benefit analysis. Rather, the Commission listed some additional information that might have made it easier to approve the proposed infrastructure rider. The AG asserts that AIU should not be allowed to implement Rider QIP by simply indicating the intent to comply with cost/benefit analyses that are largely undefined.

In addition, the AG states that Rider QIP is flawed in its failure to account for two elements of the revenue requirement calculation that change in direct relation to changes in gross plant investment – the accumulated deferred income tax reserve and the accumulated depreciation and amortization reserve. Since these balances are treated as subtractions in determining rate base, the AG avers that it is completely unreasonable for AIU to include gross plant additions within Rider QIP and not also include the growing deferred income tax and accumulated depreciation balances that also tend to increase from year to year. Mr. Brosch explains that the rider is driven by quantification of the term "NetQIP" in the tariff, which includes the "Original cost of QIP less accumulated depreciation." By defining qualifying investment this way, the tariff completely fails to account for the additional deferred income taxes arising from the incremental plant investment. Mr. Brosch also contends that there is also a problem with the narrowly defined "less accum depr" term that is used to quantify "NetQIP." The accumulated depreciation that is recognized under Rider QIP is limited to depreciation accruals only upon the new QIP Plant investment dollars. According to Mr. Brosch, in reality, AIU continues to collect depreciation and build its Accumulated Reserve for Depreciation based upon application of depreciation accrual rates to all plant investment, not just incremental new investment. In fact, he explains, depreciation on embedded prior year capital investment produces considerable cash flow for QIP that is available for reinvestment in incremental new plant, as shown in Table 9 (page 61) of AG/CUB Ex. 2.0, and that can not be ignored if a balanced tracking of changes in actual net plant investment is to be achieved through any rider tariff.

The AG identifies other mechanical difficulties in auditing Ride QIP. The AG states that neither the input values nor the computations involved in administering Rider QIP plant investment can be readily audited and verified through expedited regulatory reviews. Rider QIP relies upon several input values that should become “fixed” in this rate case, including the gross revenue conversion factor “GRCF” and the weighted cost of capital inputs "WCCE," "WCPE," "WCLTD," and "WCSTD." But, according to the AG, the quarterly capital expenditure amounts in each account that qualify for inclusion in all the calculations would need to be verified for each quarterly filing and then again in annual reconciliation filings, with interest accrued on over and under-recoveries. The complexity of the calculations involved in administering Rider QIP is evident to the AG from the four pages of single-spaced text required in AIU witness Cooper’s testimony just to define the terms involved, before any data is actually analyzed or rates calculated.

AIU apparently contemplates rapid implementation of Rider QIP quarterly rate increases, with an informational filing on the 20th day of the month preceding the effective date of the QIP surcharge percentage, which the AG fears would allow no substantive analysis or audit of the plant costs that would cause such rate increases. The AG believes that Rider QIP raises a fundamental question regarding whether it is necessary for any Staff audit or other regulatory examination to occur before new plant investments can be included within rate base for cost recovery from customers. The primary input values under Rider QIP would be the “NetQIP” recorded original cost plant additions recorded each quarter, reduced by project costs that relate to “new business.” In the event the Commission or Staff determine that any prudence review or financial audit of recorded plant investments is required prior to increasing rates to recover the incremental new NetQIP plant investment, the AG states that considerable administrative costs and procedural delays may be unavoidable with implementation of Rider QIP.

d. Legal Considerations

Among the statutory provisions that the AG has considered is Section 9-211 of the Act, which provides that a utility's rate base shall reflect only the value of such investment which is both prudently incurred and used and useful in providing service to customers. The AG contends that Rider QIP violates this precept since it permits surcharges on customer bills to cover the carrying costs of new investment before there has been any Commission review of the prudency or used and usefulness of the Rider QIP investments. While Rider QIP would include an after-the-fact prudency review as part of the annual reconciliation of the preceding calendar year rider surcharges, the AG points out that customer rates would have already increased, reflecting investment prior to any prudency assessment. The AG also objects to Rider QIP on the legal grounds that it violates the rule on single-issue ratemaking, least-cost requirements, and many of the other legal principles that it discusses in the context of Rider VBA.

4. CUB's Position

CUB objects to the implementation of Rider QIP, citing in defense of its position the rule on single-issue ratemaking, the broad scope of eligible projects under Rider QIP, the lack of any specific project plans, the delay in any customer receipt of savings, and the improper transfer of risk from shareholders to customers. CUB also states that to the extent AIU's request for Rider QIP is based on the eventual implementation of a smart grid, the rider should be rejected given AIU's lack of specificity with regard to smart grid implementation. CUB witness Cohen, though not opposed to implementation of a true smart grid where the benefits outweigh the costs, takes issue with the propriety of rider treatment for smart grid investments. Instead, Mr. Cohen recommends that the Commission order immediate commencement of a collaborative stakeholder process to examine the changing nature of the utilities' service obligations and address the costs and benefits of particular smart grid strategies. He testifies that the stakeholder process should be led by an independent expert facilitator with experience in similar processes elsewhere, who could assimilate the latest technical information and regulatory policy from around the country in a highly specialized and rapidly evolving field. Mr. Cohen believes that a high level of experience with similar processes will enable the facilitator to set the agenda, manage the flow of information, and focus the collaborative on timely achievement of its goals.

Mr. Cohen further recommends that the Commission order a statewide process to consider smart grid and related issues, in order to ensure that uniform principles, policies, and standards are applied where appropriate.

Mr. Cohen and CUB witness Kiesling both testify about the vast potential benefits of a true smart grid, but also caution that such benefits will only be realized if the Commission approaches smart grid planning strategically, and with ratepayers' best interests in mind. Mr. Cohen states that a true smart grid has the potential to facilitate optimal procurement planning as well as other system benefits. Smart grid technologies integrate electric generation, delivery, and consumption systems with communication systems to improve system function and reliability and also potentially to provide a variety of electricity products and services to the diverse range of customers in the electricity network. Further, smart grid holds the potential to reduce operating and maintenance costs while improving reliability, as well as reduce the cost of long-run generation, transmission, and distribution investments by reducing peak load.

Ms. Kiesling lays out the necessary foundations for any smart grid planning process and advises that this Commission should approach smart grid investment from a proactive and strategic policy framework stand point, rather than the reactive approach. She explains why a utility-specific system engineering process is essential at the outset, the danger of premature commitment to a particular technology, and the need to "future-proof" smart grid decision-making. Ms. Kiesling identifies the following characteristics as defining a true smart grid:

- Self-healing: a smart grid can measure voltage and frequency and detect and prevent faults and outages automatically;
- Active agent participation: customers actively participate in the network, as with demand response programs;
- Security: built-in resiliency to external attacks on the network;
- Power quality: customers can demand interruptible power supplies in exchange for lower prices;
- Interconnection: distributed generation and storage sources can interconnect within the network;
- Markets: a smart grid is a transactive, market-based network; and
- Efficiency: a smart grid optimizes resource use and minimizes waste and idle capacity.

To assist in the effective design of a smart grid, she reports that there has been industry movement toward common smart grid architecture. Ms. Kiesling cites the GridWise Architecture Council ("GWAC"), a group of experts formed by the U.S. Department of Energy, as the gold standard in interoperability principles and architectural frameworks to facilitate the smart grid.

Ms. Kiesling testifies that GWAC is dedicated to the development of interoperability principles for the modernization of the electric power network, and to facilitating the implementation of these principles. One of the GWAC's roles, she continues, is to help stakeholders understand these principles, and to provide resources to help facilitate an interoperable, modern, smart electric power network. The GWAC's Decision-Maker's Interoperability Checklist is a tool to help decision-makers evaluate options such as capital asset investments or new information technology opportunities to determine whether they contribute to interoperability. Ms. Kiesling states that decision-makers can use the checklist to review policies or infrastructure investment proposals. She recommends that these standards be applied in a multi-party process that creates a long-term smart grid strategy for AIU.

CUB asserts that the collaborative process recommended by Mr. Cohen and Ms. Kiesling would address foundational policies, as well as incorporate utility-specific issues. CUB states that policies for consideration could include, but not be limited to:

- Defining the intended functionalities and properties of a true smart grid;
- Delineating principles Illinois should use to guide smart grid planning and deployment, for example:
  - Interoperability;
  - Open Architecture; and
  - Non-discriminatory Access;
- Developing uniform Standards;
- Establishing methods of estimating, calculating, and assessing benefits and costs, including evaluation of non-quantifiable benefits (and costs);
- Identifying the implications of smart grid technology for existing policies regarding rate design, consumer protection, and customer choice;

- Evaluating the effect of statutory renewable resource, demand response, and energy efficiency goals on smart grid planning and implementation;
- Considering the import of consumer education and dissemination of information about smart grid applications;
- Access by electricity market participants to smart grid functionalities;
- Data collection, storage, management, security, and availability to third parties;
- Standards for interconnection of third party equipment; and
- Mechanisms to flow through to customers any utility smart grid revenues.

CUB adds that a critical input into the collaborative process would be information derived through internal utility design and engineering exercises using established national models, and tools to identify functionality requirements and technical standards. Ms. Kiesling further testifies that the development of a long-term smart grid strategy should include an implementation management process, facilitated by an independent third-party technical expert, who welcomes the participation of parties beyond the utility, develops specific functionality requirements, and incorporates industry-supported interoperability standards and other architecture standards.

In order to ensure sufficient interoperability, which in turn enables information sharing, enhances the reliability and effectiveness of operational and commercial functions, and a host of additional system benefits, CUB further contends that the following Interoperability Principles must be present in any smart grid plan (as reflected in the GWAC Constitution Statements of Principle):

- Respect organizational boundaries and security across the electric system supply chain. Electric system business processes must become better automated across the value chain, while respecting privacy and each business' internal processes.
- Embrace the evolutionary dynamics of business processes, technologies, and interfaces. Over time, business processes evolve and the information system interfaces that support them are smoothly modified.
- Enable the discovery and creation of new value chains and participants. New players become active participants by accessing and delivering services through information system interfaces with other organizations.
- Enhance the resilience of the system to natural or deliberate attacks. Automation with independent, distributed decision-making schemes promotes reconfiguration of the electric grid to protect and mitigate impacts.

CUB maintains that Rider QIP is incomplete and does not require the interoperability needed to ensure that these benefits are achieved. AIU's current proposal, CUB observes, includes only four criteria for smart grid investments, instead of the more comprehensive criteria listed above and discussed in more detail by Ms. Kiesling. CUB asserts that these criteria are necessary to ensure that smart grid investments are fully beneficial to AIU, customers, and the electric grid.

5. IIEC's Position

IIEC argues that Rider QIP suffers from the various problems that beset riders generally and urges the Commission to reject it and include such capital projects in annual capital budgeting processes as they are currently. IIEC states that AIU may include within the scope of Rider QIP projects such as ordinary replacements routinely performed today. Thus, IIEC believes that it is reasonable to expect that without Rider QIP AIU would continue to invest in the types of projects envisioned under Rider QIP, on the same bases it now uses for initiating construction projects, and would seek appropriate rate base treatment in its next general rate proceedings just as it does today.

Through Rider QIP, IIEC contends that AIU is attempting to shift to its customers operating risk that is traditionally borne by the utility and addressed in a traditional rate case proceeding. AIU, however, does not view rider recovery as shifting operational risk--AIU believes it merely neutralizes the risk. IIEC agrees that risks may be neutralized from a utility's perspective, but the effect is quite different from a customer's perspective. IIEC is concerned that Rider QIP would allow AIU to avoid the quantitative assessments central to rate cases that determine whether it is reasonable and prudent to replace particular facilities. While qualifying investments might eventually get the traditional level of scrutiny before permanent inclusion in base rates, IIEC asserts that the rider procedures do not provide the same apportionment of risk achieved under traditional regulation, and do not allow close scrutiny of proposed costs until after customers are charged. Despite AIU's risk neutralization theory, IIEC maintains that the near immediate rate recovery of and on new investment undeniably constitutes a major shift in operating risk to the customer.

IIEC is also troubled by the fact that Rider QIP adjusts rates on the basis of only selected cost elements, without taking into consideration other costs or factors that would affect the utility's overall profitability. AIU fails to acknowledge that savings, along with other factors that serve to reduce the revenue requirement, e.g., changes in the depreciation reserve, may negate the need for a separate rider altogether. Another concern of IIEC's is that Rider QIP also provides additional revenue to AIU without the traditional Commission review to determine the prudence of the cost and revenue elements. IIEC contends that the ratemaking approach represented by Rider QIP bears a striking resemblance to single-issue ratemaking and, thus, should be avoided.

Rider QIP's potential to distort or otherwise compromise the incentives for prudent and efficient utility operation built into the regulatory oversight and ratemaking process worries IIEC as well. IIEC states Rider QIP may create an incentive for AIU to classify expenses in a way that maximizes rider collections, rather than foregoing recovery until its next rate case. Under Rider QIP, such choices are not transparent, and IIEC believes that they would increase the difficulty of the Commission's evaluation of AIU's costs in subsequent rate proceedings. Regulatory lag will also no longer provide an incentive to control costs in order to be more profitable to shareholders and

to diminish the need for future rate cases. The relatively immediate dollar-for-dollar recovery of eligible costs, IIEC avers, eliminates the beneficial impact of regulatory lag.

IIEC indicates that Rider QIP will also potentially create new cross-subsidies. IIEC witness Stephens testifies that if the structure of a rider is such that it collects revenues from customers on bases different from those used in recovering similar costs through base rates, or if the rider is otherwise not reflective of cost-causation, it creates a subsidy and should not be approved. In addition to the forecasted capital and O&M expenditures listed by Mr. Nelson, AIU is studying smart metering and smart grid technologies that AIU claims may provide future benefit to customers. While IIEC agrees that smart grid and smart metering may be the delivery service system of the 21st century, it points out that many large industrial customers already have relatively advanced metering installations, whether provided by AIU, by their own investments, or through a retail electric supplier. IIEC fears that Rider QIP could make them pay twice. In a traditional comprehensive rate case, with appropriate cost studies, IIEC states that facilities deployed to enhance the reliability of the delivery system would likely be allocated among potential beneficiaries on the same basis as the assets made more reliable. Rider QIP does not incorporate any process to allocate costs to those who receive the direct benefit of the investment eligible for cost recovery under the rider. Therefore, of necessity there will be cost subsidies in favor of those customers that do directly benefit, according to IIEC.

An additional problem with Rider QIP identified by IIEC is that the rider seeks to recover costs that need not be incurred to meet AIU's statutory service obligations. Through Rider QIP, AIU seeks to study and invest in smart grid technologies. A smart or modernized grid is a delivery system that uses advanced sensing, communication, and control technologies to generate and distribute electricity more effectively, economically, and securely. These capabilities, IIEC argues, in addition to not being proven, are not needed to meet AIU's service obligations. To the extent that AIU's proposed smart grid projects under Rider QIP are necessary or beneficial to consumers and determined to be good, prudent projects to undertake, IIEC contends that AIU should address them as part of the normal capital budgeting process and seek recovery in its next rate case. IIEC notes that AIU began a 4-year deployment of AMR technology in May 2006 and has apparently been able to deploy this technology as part of its normal budgeting process.

IIEC opines that Rider QIP projects also could allow AIU to provide services on a competitive basis. While it is not clear exactly what functionalities ultimately will be available through a smart grid or other advanced technologies, AIU mentions in its testimony that it is conceivable that those functionalities will allow it to provide services that extend well beyond those associated with electric delivery service. IIEC indicates that there may be new business opportunities for AIU, or an unregulated affiliate, to provide value added services related to data management, energy facilities management, or even voice or data communications all underwritten through regulated rates.

From an administrative standpoint, IIEC contends that Rider QIP will require increased regulatory complexity that will be burdensome for many stakeholders. AIU has committed to paying a combined annual fee of $100,000 for the annual filings to mitigate the burden on Commission resources. Outside of the $100,000 pledge, AIU is short on details as to the proposed process and procedure for the Commission pre-approval. As AIU's annual $100,000 pledge to the Commission demonstrates, IIEC states that participation in repeated regulatory proceedings before the Commission can be an expensive proposition for intervener parties. In fact, IIEC relates that AIU does not even know if $100,000 is sufficient to mitigate the drain on the Commission resources. Furthermore, AIU has not given consideration to paying the participation fees of other parties. No matter the level of participation, IIEC fears that the evaluation and study likely will be less than that which would typically occur in a general rate case.

6. AARP's Position

AARP objects to the additional cost burdens that Rider QIP may impose on customers who have no interest in supporting AIU's investment in or ever taking advantage of new smart grid technology for discretionary and non-essential services. In terms of legal arguments, AARP asserts that Section 9-211 of the Act requires that the determination of any rate or charge shall include only investment that is prudently incurred and is used and useful in providing service to customers. AARP states further that Section 9-215 charges the Commission with the task of determining whether a utility's capacity is in "excess of that reasonably necessary to provide adequate and reliable electric service." Section 8-401, AARP adds, requires Illinois public utilities to provide service and facilities in a manner that constitutes the "least cost of meeting the utility's service obligations." AARP claims that this legal framework for ratemaking would be violated by AIU's proposal to fund projects that exceed its basic obligations through a mandatory surcharge. Rider QIP, AARP argues, is fundamentally at odds with Illinois law, especially if it were approved as an "empty rider" with particular projects to be determined through subsequent Commission proceedings. AARP contends that such a decision would establish a "blank check" to be filled in later—outside the full review and protections provided to consumers by a general rate case. The law requires, AARP insists, that basic electric delivery rates be limited to funding only those projects that do not exceed the least cost method of providing what is necessary for adequate and reliable electric service. AARP states further that Rider QIP violates the general rule against single-issue ratemaking.

Among the policy reasons that Rider QIP should be rejected, according to AARP, is the fact that it would inappropriately shift the responsibility and risk of capital investment between rate cases away from shareholders and onto ratepayers. If AIU believes that its expenses or costs, including the cost of financing distribution system capital additions, are increasing more rapidly than its revenues such that a revenue deficiency is being created, AARP reminds AIU that it has the option to file for a rate increase. AARP notes that AIU has not identified any prohibitions on its ability to file base rate cases to address distribution system plant additions. Currently, the risks and benefits lie with shareholders during the period between rate cases if revenues grow

more slowly or more rapidly than AIU's costs. AARP argues that Rider QIP would shift the risk of financing distribution system capital investment onto ratepayers by making ratepayers responsible for capital expenditures between rate cases. AARP observes, however, that AIU would still retain the benefit of revenue growth and expense reductions between rate cases for its shareholders. AARP contends that such a non-symmetrical ratemaking approach is extremely unfair to consumers.

A second policy reason discussed by AARP as to why Rider QIP is inappropriate is that it would remove or reduce the current incentives to prudently control the cost of plant additions. One of the useful functions of regulatory lag is to place financial responsibility upon the utility for fluctuations in costs between rate cases. AARP states that the regulatory lag feature of Rate Base/Rate of Return regulation is essential to effective and efficient operation of such a regulatory régime. In evaluating plant additions, AARP states that AIU should conduct a cost-benefit analysis to determine if there is a business case for making the expenditure and for prioritizing between competing uses of capital resources. If the case is compelling and the project is cost-justified, AARP contends that no additional rider or adjustment clause is needed. If the project is not cost-justified or the benefits are too speculative to warrant the commitment of funds, AARP suggests that it may be prudent to delay or avoid the related capital expenditures. These incentives that are currently in place would essentially be eliminated if Rider QIP were to be approved, according to AARP.

AARP's third policy argument against approval of Rider QIP is that the costs at issue are not appropriate for rider recovery. Despite AIU's claims, AARP contends that the distribution system costs that could be included in Rider QIP would not be similar to power supply costs. AARP notes AIU's acknowledgment that a rider mechanism is a more appropriate cost-recovery mechanism for costs and other rate inputs that are highly volatile, uncontrollable, and/or unpredictable. AARP contends, however, that distribution system capital investments and plant additions generally are not highly volatile, uncontrollable, and/or unpredictable. Many electric utilities have adjustment clauses to address the rate recovery of their large and volatile fuel and purchased power costs, and the primary factor typically cited in justifying the implementation of fuel and purchased power cost recovery mechanisms is that these costs are highly volatile, uncontrollable, and/or unpredictable. AARP asserts that distribution system capital additions are very different and offers the table on page 10 of AARP Ex. 1.0 to demonstrate the differences.

A fourth policy argument against Rider QIP is that it is simply not needed. AARP observes that the lack of such a rider has apparently not deterred AIU from making investments in the past which were necessary to meet its service obligations to its customers. Consequently, AARP contends that it is not appropriate to now set aside this one single issue for future recovery.

AARP's fifth argument against Rider QIP concerns Mr. Nelson's testimony that Rider QIP would facilitate investments in smart metering and smart grid technology. AARP is troubled, however, by the fact that AIU is still evaluating the benefits, costs,

and timing associated with implementing smart metering and smart grid technologies and has no firm plans in place at this time. AARP maintains that AIU should not be given the go-ahead to shift the risk of such projects that it may not otherwise construct, and which would not meet AIU's normal financial and economic analysis and capital expenditure prioritization screening, particularly when it has no definitive plan. AARP reminds the Commission that the concepts of smart grid and smart metering are not a replacement for aging infrastructure but rather an entirely new system that would be placed on top of the basic electric delivery system—the cost of which should definitely not be passed through a rider.

AIU would be better served, according to AARP, to look at other electric utilities that are implementing smart grid projects on an experimental basis without seeking advanced regulatory approval to charge the costs incurred to ratepayers. As an example, AARP points to Xcel Energy ("Xcel"), which has recently announced its plans to implement an advanced, smart grid system in Boulder, Colorado. (See AARP Exs. 2.1 and 2.2) Having established a collaborative effort with other firms and leveraging other sources including governmental grants, AARP reports that Xcel anticipates funding only a portion of the smart grid project itself. AARP adds that Xcel is not seeking permission from regulators to recover its costs in advance, but will wait until it has assessed and proven the benefits. AARP states that the approach advanced by Xcel, where the utility is assuming the initial risks of installing smart grid technology and evaluating whether it is producing benefits (consistent with the very underpinnings of rate of return regulation), stands in stark contrast with AIU's approach.

AARP's sixth policy argument against Rider QIP relates to the future project reviews before the Commission. Specifically, AARP believes that it is unlikely that it would have funding for legal and consultant participation in those subsequent proceedings or the proposed annual Rider QIP reviews. Although AIU offers to contribute money to offset the impact on Staff's resources, AARP notes that AIU made no such offer to interveners. Under the general Rider QIP process set forth in the record, AARP fears that intervener participation is likely to suffer. Consequently, AARP would prefer to see AIU's capital projects continue to be addressed in the context of general rate cases, and not be forced to consider representation in additional separate proceedings in order to provide input on rate increases outside of the protections of such general rate cases.

7. LGI's Position

LGI urges the Commission to reject Rider QIP. To begin with, LGI indicates that Rider QIP is no better than the comparable infrastructure rider recently rejected by the Commission in Docket Nos. 07-0241/07-0242 (Cons.). LGI also contends that Rider QIP violates the rule against single-issue ratemaking, since it does not consider any other impacts on costs. The rider, LGI adds, inappropriately shifts the operating risk from AIU to customers since it seeks preapproval of a project and guarantees that AIU will recover not only its costs but also a return on its investment. By granting approval between rate cases, LGI states that Rider QIP eliminates the regulatory lag for recovery

of expenses and through a yearly process it will unduly burden customers who must spend additional funds to intervene and participate in the annual approval process. LGI concurs with AG/CUB witness Brosch and Staff witness Stoller that the definitions contained in Rider QIP are far too broad and cover routine items that are typically and more appropriately considered in a traditional rate case. If implementation of a smart grid is a goal, LGI also agrees that interested parties should first collaborate on what needs/ought to be done before essentially using Rider QIP to pay for whatever AIU decides to do.

8. Kroger's Position

Kroger argues that Rider QIP should be rejected as a form of single-issue ratemaking. When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers, Kroger notes that the standard practice is to review and consider all relevant factors, rather than just a single factor. To consider some costs in isolation might cause a commission to allow a utility to increase rates to recover higher costs in one area without recognizing counterbalancing savings in another area. Furthermore, Kroger maintains that the facts surrounding Rider QIP do not trigger any of the exceptions to the general prohibition against single-issue ratemaking.

As a public utility, Kroger asserts that it is AIU's responsibility to provide safe and reliable service to its customers. In meeting this responsibility, Kroger states that AIU must set budget priorities and invest sufficient capital to maintain and improve its system. The responsibility, Kroger continues, to ensure that proper investment priorities are developed and implemented rests with AIU's management. If system improvement projects are prudent investments, Kroger contends that management should fund them and seek cost recovery through conventional ratemaking treatment. Kroger does not believe that it is in the public interest to resort to single-issue ratemaking to ensure funding of necessary distribution infrastructure.

9. Commercial Group's Position

The Commercial Group indicates that its members have operations across the United States and have noticed an increase in applications by utilities for rider recovery of various costs. The Commercial Group believes that such rider recovery mechanisms shift risk of recovery of costs between rate cases from the utility to ratepayers. Therefore, it contends that riders should only be approved in extreme situations pursuant to established legal standards. According to the Commercial Group, Rider QIP does not meet these standards.

Under Rider QIP, the Commercial Group states that AIU could recover costs incurred between rate cases without a prudency or reasonable cost finding and without a corresponding cost reduction analysis. The Commercial Group considers this single-issue ratemaking that would increase rates overall. Furthermore, it adds, none of the costs in question are extraordinary or volatile in nature so as to justify rider recovery.

Instead, the Commercial Group contends that some of these investments appear discretionary in nature and might not be made by AIU if Rider QIP is not approved and could produce revenue streams from new non-essential services. Therefore, if recovery of discretionary plant costs is to be allowed that may produce non-utility revenue, the Commercial Group recommends that more administrative oversight be required to ensure that ratepayers do not overpay for utility service. The Commercial Group, however, contends that it would be administratively difficult for it to participate in the "extra" proceedings contemplated under Rider QIP. It notes that it is expensive and cumbersome enough for interveners to hire consultants and attorneys for rate cases. Expecting them to do so for additional Rider QIP proceedings is not realistic. Thus, the Commercial Group fears that intervener input would effectively be eliminated from a significant portion of costs that by their nature require more, not less, oversight.

10. Commission Conclusion

Clearly Rider QIP has generated a great deal of controversy. While the Commission certainly does not object to the general idea of improving the electric distribution system (including implementation of smart grid technology), care must be given to ensure that it is done in a practical and cost effective manner. Cost recovery for such efforts must also be thought through. AIU proposes to recover capitalized expenditures related to system modernization and service reliability enhancements through Rider QIP. Every other party to this proceeding generally considers a rider an inappropriate way to recover such costs, for both legal and practical reasons.

The Commission has recently given the use of riders as a cost recovery mechanism a great deal of thought (see Docket Nos. 07-0241/07-0242 (Cons.)). In the proper case, riders may be used to recover certain utility costs. Typically such costs are unexpected, volatile, or fluctuating expenses, as discussed in BPI II. With regard to Rider QIP, AIU hopes to use it to recover several hundred million dollars in capital expenditures related to infrastructure improvement over a period of years. Several of the parties argue that the types of projects/expenditures that AIU seeks to pass through under Rider QIP are not unexpected, volatile, or fluctuating. IIEC contends that the long-term, planned system improvements that AIU describes (See AmerenIP Ex. 2.0E at 27-28) are the most expected, least unpredictable, and most controllable of utility costs. IIEC therefore maintains that they should receive comprehensive review and approval, not truncated examination and pre-approval under a rider.

To bolster the argument that the expenses at issue are not appropriate for rider treatment, the AG asserts that AIU's historical and projected investment levels in electric distribution plant do not indicate cost volatility or any apparent inability to manage and control spending. The AG relates that past and future budgeted electric distribution plant spending has been and is expected to remain relatively stable, with an average expenditure level for the period of 2004 through 2011 of $157 million. Minimum spending of $121 million (23% less) occurred in 2005 and maximum planned spending of $181 million (15% more) is budgeted in 2008. AIU's historical actual capital expenditure levels have been similarly non-volatile. For the years 2004 through 2006,

the AG reports that actual annual Gross Construction Expenditures, as shown on AIU's First Revised Schedule WPD-7, page 5, have ranged from $54 to $57 million per year for AmerenCILCO, $45 to $82 million for AmerenCIPS, and $134 to $177 million for AmerenIP.

Upon reviewing the record, the Commission is not convinced that the costs in question are appropriate for rider treatment. While AIU argues that the amounts are significant and will allow it to improve the reliability of its distribution systems, the Commission does not believe that they rise to a level necessitating rider treatment nor are they for projects whose nature warrants rider treatment. The projects/activities identified by AIU witness Nelson include, among others, pole replacement, line rebuilding, transformer purchases, inspections, and tree trimming. The costs for these types of projects and activities are typically addressed in a rate case since they are consistent with the everyday business of operating and maintaining an electricity distribution company. Some such projects may also reduce operating expenses; since there is no mechanism to pass savings on to customers, the specter of single-issue ratemaking arises as well.

Additionally, the Commission questions whether a financial need for such rider treatment exists in order to fund the projects described. AIU has offered no compelling evidence of financial need. The AG points out that AMS' Managing Supervisor of Business Performance, Mr. Getz, oversees the capital budget process and testifies that he was unaware of any specific projects that AIU was unable to finance through internally generated funds and the capital markets that would be appropriate for Rider QIP inclusion. The AG is also concerned by Mr. Getz's testimony that Rider QIP would simply provide additional funds for the financing of capital projects “that may not make the cut today.” (Tr. at 606) The Commission concurs with the AG that such testimony raises a question of whether Rider QIP may induce AIU to invest in certain capital projects that are otherwise only marginally justified under AIU's economic analyses.

Even for those projects which may go beyond the customary operation and maintenance expenses, AIU has failed to persuade the Commission that Rider QIP is necessary. In fact, the Commission notes that AIU elected to deploy AMR under traditional regulation and without any rider recovery mechanism. The Commission sees no reason why other such project costs could not be recovered through a traditional rate case.

This is not to say that infrastructure costs could never be recovered through a rider. Under the proper circumstances, the Commission may be persuaded that such costs are appropriate for rider treatment. But under the facts presented here, the Commission concludes that Rider QIP is not the proper means to recover the costs in question. AIU's reliance on IAWC's Qualifying Infrastructure Plant Surcharge Rider as support for recovering general infrastructure costs through a rider is misplaced. IAWC's infrastructure rider is the result of specific legislation (Section 9-220.2 of the Act), whereas no such legislation exists for electric utility investment.

Other practical reasons exist for rejecting Rider QIP. As noted above, AIU proposes to pass expenditures related to system modernization and service reliability enhancements through Rider QIP. Plant additions associated with new customers, however, would not qualify for the rider because those projects would produce additional revenue. The problem is that it is not always easy to distinguish the type of project. Some projects may have multiple elements and it is unclear how costs would be recovered if Rider QIP were in place.

Another practical concern is the timeframe for review of proposed expenditures under Rider QIP. AIU proposes that 10 months be allowed for a docket in which Staff and any interveners could participate and weigh in on the costs and benefits of AIU's proposals. Without knowing what/how many projects AIU may seek to pass through Rider QIP, it is difficult to know whether 10 months are appropriate for such a review. Moreover, such additional dockets will increase costs to potential interveners and further drain Commission resources. AIU apparently recognizes the pressure on Commission resources since it has offered to contribute $100,000 to cover the impact on Commission resources as a result of reviewing additional rider filings. Acceptance of this money, the Commission believes, leads to the appearance of impropriety. Furthermore, it is not clear whether AIU would attempt to recover the $100,000 from customers, which would exacerbate the impact of Rider QIP on customers.

With regard to AIU's suggestion that smart grid costs may be recovered through Rider QIP, the Commission is even less comfortable with that idea. While the Commission believes that moving toward a smart grid is appropriate, plans to do so must be well thought out. Before the Commission will consider cost recovery for smart grid improvements, it must be confident that the improvements are practical and cost effective. At this time, it does not appear that AIU is close to having a plan for implementing a smart grid.

Among the concerns expressed about smart grid costs and Rider QIP is AARP's objection to the additional cost burdens that Rider QIP may impose on customers who have no interest in supporting AIU's investment in or ever taking advantage of new smart grid technology for discretionary and non-essential services. AARP also fears that AIU or Ameren may generate unregulated revenue from smart grid investments paid for by customers. AARP seems to suggest that customers should share in such revenue if they are forced to pay for the system enhancements that made the revenue possible.

Another concern regarding smart grid costs and Rider QIP comes from IIEC. While IIEC agrees that smart grid and smart metering may be the delivery service system of the 21st century, it points out that many large industrial customers already have relatively advanced metering installations, whether provided by AIU, by their own investments, or through a retail electric supplier. IIEC fears that Rider QIP could make them pay twice.

Such concerns of AARP, IIEC, and others all must be considered in determining how to implement and pay for smart grid technology. CUB and others recommend that the Commission direct AIU to participate in statewide smart grid workshops to essentially develop a plan for implementing smart grid technology. CUB made a similar, if not the same, proposal with respect to Rider SMP in Docket No. 07-0566. In that docket, the Commission agreed with CUB's proposal, and approved a Statewide Smart Grid Collaborative based on CUB's recommendation but with minor modifications. (See 07-0566 Order at 140-42 (Sept. 10, 2008)) The intent of the 07-0566 Order was for "the two large investor owned utilities regulated by this Commission" to be involved in a single statewide smart grid collaborative. (Id. at 141) In addition, the 07-0566 Order includes details about the hiring of a facilitator, recovery of costs and the reports that are to be filed. It would be redundant to approve a second smart grid collaborative within this docket, therefore the Commission concurs with CUB's recommendation in this docket and directs AIU to participate in the statewide smart grid workshop, as is established in the 07-0566 Order on pages 140 to 142, under the heading "Statewide Smart Grid Collaborative." In that section of the Order, the Commission describes the duties, responsibilities and guidelines of the Statewide Smart Grid Collaborative, and as such, the Commission holds that section also applicable to AIU. There may have been certain issues raised in this docket that only apply to AIU; therefore, AIU, Staff, and other interested parties shall also address those in the Statewide Smart Grid Collaborative. Other relevant issues may certainly be addressed as well.

The goal of the Statewide Smart Grid Collaborative is to enable AIU to determine whether a smart grid proposal is feasible for its system and is beneficial. After the Statewide Smart Grid Collaborative is concluded, if AIU chooses to pursue the development of a smart grid, it should file its comprehensive smart grid plan – evaluating costs and benefits – with the Commission for review and approval. In Docket No. 07-0566 the Commission also set forth certain guidelines for such a filing. As the Commission did in the preceding paragraph, it sees no need to restate those guidelines herein, but instead, directs AIU to follow the process already outlined in the 07-0566 Order (under the heading "Smart Grid Implementation Docket"). Following the conclusion of the Statewide Smart Grid Collaborative, Staff shall timely submit a report to the Commission discussing the outcome of the workshops and making recommendations for further action.

A distinction between this case and the decision in the 07-0566 Order, is that the Commission is not approving a workshop process focused only on advanced meter infrastructure ("AMI"). In 07-0566, ComEd was approved to install AMI in what was identified as Phase 0. Phase 0 included a workshop process to develop project goals, timelines, evaluation criteria and technology selection criteria. Such a workshop is not needed at this time for AIU, since we are not granting approval to AIU to install AMI.

Thus, the Commission agrees with CUB's recommendation for a smart grid collaborative, and directs AIU to participate in the "Statewide Smart Grid Collaborative" established in the 07-0566 Order and abide by the guidelines outlines in the "Smart Grid Implementation Docket" in Docket No. 07-0566. The Commission is making the above

findings so as to be consistent on this issue between the 07-0566 Order and this docket.

VIII. COST ALLOCATION METHOD

As a part of every rate case, the Commission must determine what portion of a utility's costs each class of customers will be responsible for. Each of the three utilities currently divides retail electric customers into five classes. The DS-1 tariff class contains meter, customer, and delivery charges for residential customers. The DS-2 class presents meter, customer, and delivery charges for non-residential customers with demands up to 150 kilowatt ("kW"). The DS-3 class includes meter, customer, delivery, and transformation charges for non-residential customers with demands of 150 kW-1,000 kW. The DS-4 class includes meter, customer, delivery, transformation, and reactive demand charges for customers with demands exceeding 1,000 kW. The DS-5 class presents fixture charges for lighting customers. The three utilities do not currently have uniform gas delivery classes, but have proposed revisions in this proceeding toward that goal.

Generally, the Commission prefers to allocate costs among the various classes as close to the cost of serving each class as is reasonably possible and/or appropriate. The purpose of doing so is to assign costs to those who cause them. The Commission typically accomplishes this goal through a cost of service study ("COSS"). From time to time, however, circumstances arise that warrant allocating costs at least in part on non-cost based criteria. Whether such circumstances are present in this proceeding is discussed below.

A. COSS-Based Rates vs. Across-the-Board Rate Changes

1. AIU's Position

Pursuant to Section 285.5110 of Part 285, AIU included with its rate filing a COSS for gas and electric service. AIU, however, did not follow the results of the class cost of service at equalized class rates of return in determining class revenue requirements. Rather, AIU proposes to equally apply the overall base rate percentage change on an across-the-board basis. For its gas business, AIU agrees with Staff that the across-the-board increase target should exclude Other Revenues and Special Contract Revenues.

In explaining its position, AIU first states that one must understand that rate structures often consist of a combination of both cost of service and other non-cost considerations. AIU indicates that there are numerous non-cost factors that can and do influence rate design such as rate stability and continuity, competition, customer bill impacts, and the current political environment. AIU asserts that these factors may produce rates that vary from class cost of service.

AIU states further that in Docket No. 07-0165, the Commission recognized that AIU electric customers experienced significant bill impacts in 2007 due to the major transition from frozen and reduced, bundled 1997 electric rates to post-2006 rates that included market value prices for power and energy. AIU notes this transition received much attention and resulted in new legislation to mitigate bill impacts to the DS-1 and DS-2 classes. AIU adds that approximately 80% of its gas customers are also electric customers. AIU states that the major impact of the transition in electric rates mentioned above along with the large percentage of combination accounts were major drivers in the decision to distribute the revenue changes in this case on an across-the-board basis. AIU asserts that the Commission's Order in Docket No. 07-0165 redesigned electric rates in an effort to mitigate bill impacts, and reflected a movement to a more equitable sharing of the post-2006 rate increase between the residential and the small general service rate classes. According to AIU, the Order effectively required a departure from strict cost-based rates to "more just and more reasonable rates." Furthermore, because these electric rates have been in effect for such a short period of time (since January 1, 2008), AIU does not believe that it would be prudent to significantly alter them in this proceeding. AIU states that the circumstances are similar with the demand based rates for the DS-3 and DS-4 classes, which were adjusted by a relatively small amount in October 2007 to reflect implementation of a rate limiter, and its gas rates, which experienced price changes in December 2007.

Additionally, AIU notes that all of its customers (i.e., residential, commercial, and industrial) have seen unprecedented increases in energy bills, gasoline prices, and healthcare costs over the last several years. While rates should track costs, given due consideration to all the factors mentioned above, AIU believes that it is just and reasonable to effectuate across-the-board revenue changes by class in this case. AIU, however, reserves the option to utilize class COSS in future rate proceedings for the allocation of class revenue responsibility.

As suggested above, AIU generally seeks to maintain the existing pricing structure approved in the last delivery service proceeding, as modified by the rate redesign docket. One exception concerns the DS-1 customer, meter, and distribution delivery charges. AIU determined that for the purposes of this proceeding to no longer seek uniformity and instead agreed to adjust those charges by a level equal to the average change in residential delivery service revenue for each of the three utilities. AIU understands that Staff and the AG agree with its changes on this issue. AIU, however, generally favors the standardized approach since from an incremental cost perspective, there is very little difference in customer or meter costs among the three.

For the DS-2, DS-3, and DS-4 classes, AIU proposes to maintain uniform meter and customer charges across the three utilities. AIU also proposes to maintain uniform transformation (for both DS-3 and DS-4) and reactive demand (DS-4 only) charges. AIU states that the distribution delivery charge is proposed to "float" to recover the remaining revenue requirement targeted for each class. To the extent there are seasonal (DS-1 and DS-2) or voltage differentiated (DS-3 and DS-4) distribution delivery charges, such charges will be adjusted by a uniform percentage by utility and

by class to arrive at the targeted revenue requirement. For the DS-5 class, all fixture and delivery charges are proposed to be adjusted on an equal percentage basis to recover the targeted revenue requirement.

Although Staff expresses some concern with using uniform non-residential customer, meter, transformation, and reactive demand charges among the three utilities, AIU contends that there are numerous benefits to uniform charges. Such benefits include the reduction in oversight by customers and Alternative Retail Electric Suppliers ("ARES") operating in multiple jurisdictions; price consistency which enables consistent decisions by customers concerning transformer, substation, or capacitor bank ownership; and uniform charges reflecting the associated incremental costs. AIU also explains that by using such uniform non-residential charges, it is able to avoid a revenue deficiency that would result under Staff's proposed across-the-board increase to all rate elements. (See AIU Initial Brief at 311-312)

While IIEC does not oppose uniform customer, meter, transformation, and reactive demand charges, AIU notes that it does take issue with increasing those existing charges because it doubts that the underlying replacement cost forming the basis for the charges have increased by a similar amount. AIU explains, however, that the overall revenue recovered from customer and meter charges was tied to the overall customer and meter embedded component cost of service in the previous delivery services rate case, not a replacement cost as suggested by IIEC witness Stephens. AIU states that incremental costs were used to develop voltage differentiated meter and customer charges, and justify uniform charges, but were not used to determine how much revenue to recover from those charges. In this case, AIU says that it was assumed that if the revenue requirement was increasing by 28% for the DS-3 and DS-4 classes, the customer and meter revenue contribution should increase by a similar amount. Moreover, AIU adds, assigning no increase to the customer, meter, transformation, or reactive demand charges would require all of the increase to be assigned to the distribution delivery charge. AIU contends that it is not reasonable to assume that all of the increase in the revenue requirement assigned to a class occurred in the demand-based distribution delivery charge, while the demand-based transformation and reactive demand charges receive no increase. Regarding the transformation and reactive demand charges, AIU state that those services were priced using an incremental cost analysis in the previous delivery services rate case. AIU relates that proposed prices for both of those services are still within the cost ranges provided in the previous delivery services rate case.

With respect to the principles of cost of service rate design, AIU does not disagree with IIEC witness Chalfant’s assertions that adhering to cost of service principles promotes equity, engineering efficiency, stability, and conservation. But as indicated above, AIU also recognizes that factors other than cost of service are relevant to determining class revenue requirements. AIU states that it will continue to maintain a long-term commitment to consider rates that reflect cost causation and equitable cost recovery principles as well as other methods for determining class revenue

requirements and associated rate design that AIU feels appropriate at the time to present to the Commission.

Ameren Ex. 27.1 presents a comparison of AIU's and IIEC's proposed rates. AIU submits that in all cases the residential class will receive a greater allocation of revenue responsibility under the IIEC proposal. AIU also observes that the large volume delivery service class will receive a lesser allocation of revenue responsibility under the IIEC proposal than the AIU proposal. Additionally, AIU states that one should consider that the delivery component of a residential customer's bill represents approximately 25% to 33% of the bill, while natural gas supply represents the other 67% to 75%. AIU notes that the delivery service component of a large volume non-residential customer typically represents less than 25% of the total bill with the remaining natural gas supply portion representing more than 75%. As a result, AIU states that any proposed distribution service revenue allocation has, on a total bill basis, a greater impact on residential customers and less of an impact on large volume customers. AIU concludes that IIEC's proposal for allocating greater revenue responsibility to the residential class exacerbates this condition. In response to Mr. Chalfant's claim that the future elimination of subsidies will only be more painful if additional subsidies are added in this case, AIU contends that he has not provided any evidence that supports this statement and thus it should be afforded little weight.

With regard to IIEC's recommendation concerning the use of the minimum distribution system ("MDS") concept in allocating costs, AIU agrees that it has theoretical potential, but believes that the issue of implementing MDS is not ripe at the present moment. According to IIEC witness Stowe, MDS recognizes there are delivery service costs directly attributable to electrical industry mandated safety and reliability requirements for distribution facilities, and that do not vary with customer demand. Mr. Stowe contends that those costs should not be allocated on the same basis as demand related distribution system costs. AIU finds Mr. Stowe's analysis flawed because he uses improper data to derive his recommendations. AIU contends further that his analysis unduly relies on safety and reliability concerns as the premise for immediate use of MDS calculations.

AIU asserts that proper development of an MDS-based recommendation requires the use of AIU's specific COSS data, however, Mr. Stowe elects to rely on COSS data from other electric utilities instead. In fact, AIU observes, of the five data sets used by Mr. Stowe, four are from one single conglomerate utility: the Aquila Networks. AIU argues that this choice of data sets and the assumptions made by Mr. Stowe combine to create unusable recommendations. First, AIU maintains that it is fundamentally unsound to use one utility's COSS data to set rates for another utility because each utility has its own distinct set of characteristics that determine what fixed and demand-unrelated costs it faces. AIU points out that the NARUC Electric Utility Allocation Manual ("Manual") relied upon by Mr. Stowe makes this point clear, noting:

> Each utility is a unique entity whose design has been dictated by the customer density, the age of the system, the customer mix, the terrain, the

> climate, the design preferences of management, the planning for the future and the individual power companies that have merged to form the utility. (NARUC Manual at 19)

As Mr. Stowe's data shows, even within a single network, cost allocations for one account may be more than twice as high for one utility than it is for another. AIU compares the 18% demand-related share of FERC Account 366 for Aquila WPK with the 37% share of the FERC account for Aquila L&P. Across utilities from different networks, AIU asserts that variances may be absurdly incomparable – comparing the 82% demand-unrelated share of FERC Account 366 for Aquila WPK with the 6% demand-unrelated share for AmerenUE. AIU states further that the use of averages does not remedy discrepancies when such large variances are involved. At best, AIU contends that use of another, unrelated utility's COSS data might provide a generalization that helps indicate the basic contours of AIU's own cost structure. At worst, however, use of such data to pinpoint the exact division between demand-related and demand-unrelated costs for AIU results in absurdly inaccurate recommendations.

AIU's second complaint is that Mr. Stowe's assumptions are unsupported. According to AIU, Mr. Stowe assumes that his selected data sources – the four Aquila utilities and AmerenUE – represent operations similar to those within the AIU territories. The extreme variations in the data, AIU argues, belie this claim of representative consistency. As Mr. Stowe explains in rebuttal, he also assumes that safety and reliability requirements are necessarily customer-related. Specifically, he states: "This treatment [by AIU, of FERC Accounts 364-367] assumes that the standardized safety and reliability requirements have no effect whatsoever on these costs." (IIEC Ex. 9.0 at 2) AIU asserts that this statement is unsupported and should be disregarded. AIU acknowledges that safety and reliability requirements have an effect on costs, but it does not agree that safety and reliability requirements are necessarily customer related. Mr. Stowe continues: "[F]urthermore, [AIU] incurs these costs for every additional customer it serves, and the costs are independent of customer demand and energy. Ameren recognizes this to be the case and has stated in past cases, as well as in the present case, that the MDS concept has merit." (IIEC Ex. 9.0 at 3) Recognizing that the MDS concept has merit, AIU counters, is not the same as recognizing that costs for minimum safety and reliability standards are independent of customer demand and energy.

Third, AIU argues that the average percentages used by Mr. Stowe to classify distribution plant into customer and demand related categories are thoroughly suspect because the data sets he uses are poor proxies for AIU's cost structure. For instance, AIU states that the Colorado Aquila study took into consideration FERC Accounts 364-368; however, the study Mr. Stowe presents only includes FERC Accounts 364-367. AIU notes further that the data sets used for the Aquila studies are several years old. Finally, AIU observes that Mr. Stowe was unaware of whether the Aquila labor rates reflected in the FERC accounts were the same or different from AIU.

2. Staff's Position

Staff supports increasing existing rates on an equal percentage, across-the-board basis. Staff believes that this approach provides the most consistency with the rates developed in Docket No. 07-0165 to address bill impacts. Moreover, Staff continues, at this juncture there is no evidence to indicate that one group of AIU customers can more easily absorb a greater bill increase than another group of customers. Staff contends that the across-the-board approach appropriately recognizes that bill impacts are the overriding concern for AIU ratepayers in the current period. Furthermore, Staff asserts that it would not make sense to revise the design of AIU's electric rates since less than a year would have passed since the rate design was modified in Docket No. 07-0165. The Commission engaged in that redesign effort to mitigate the unexpected burden on customers and ensuing outrage. Staff does not believe that the concerns of AIU's customers about bill impacts have disappeared and contends that an equal percentage increase would signal to AIU's customers that the impact of higher rates will be equally distributed.

Staff expresses concern, however, that AIU diverges from the across-the-board approach by advocating uniform transformation and reactive demand charges across utilities. Staff is not persuaded by AIU's arguments that uniform charges would reduce the requisite oversight by customers and ARES operating in multiple jurisdictions or promote price consistency that would produce consistent decisions by AIU customers in Illinois concerning owning transformers, substations, and capacitor banks. Because the focus of rate design in this proceeding has been bill impacts, Staff maintains that the means to address those impacts is across-the-board increases of existing rates. Staff does not believe that it would make sense from a consistency standpoint to adopt this across-the-board approach for the large majority of charges while making exceptions for this small set of charges. Additionally, it is difficult for Staff to conceive how the specific exceptions proposed by AIU will benefit the ratemaking process.

One ratemaking proposal that Staff finds acceptable is AIU's recommendation to change the way billing demand is recorded. Currently, charges are based on maximum monthly demands for customers, regardless of when they occur. The new proposal would base maximum demands on the higher of: 1) maximum on peak demands, or 2) 50% of maximum off-peak demands. Staff finds this change reasonable because it will send price signals that encourage usage patterns that save money for AIU and all ratepayers. Staff states that the larger role played by peak demands in determining billing demands will encourage DS-3 and DS-4 customers to shift demands to the off-peak period. According to Staff, any shift in demand will relieve price pressure in the generation market during the peak period when prices should be the highest and also reduce peak period capacity constraints for the delivery system.

Because it advocates an across-the-board approach to revising AIU's rates, Staff does not discuss any concerns with the COSS submitted by AIU. Staff does, however, address the MDS proposed by IIEC. Staff understands Mr. Stowe to argue that there is a minimum cost incurred by any utility when it extends its primary and secondary

distribution system, replaces a component on those systems, or connects an additional customer to them. Staff further understands Mr. Stowe to say that the MDS approach classifies and allocates a portion of the distribution system on a customer basis. Staff notes that Mr. Stowe acknowledges that the Commission has consistently rejected the MDS in the past. Contrary to his contention that the Commission's prior experiences with MDS were heavily policy-oriented and theoretical, Staff submits that the Commission has taken a practical approach to MDS by recognizing that the MDS theoretical method of identifying the costs of connecting customers to the distribution system presents problems.

Staff also disagrees with Mr. Stowe's suggestion that the Commission has not previously considered utilities' obligation to comply with safety and reliability criteria when designing distribution systems. According to Mr. Stowe, utilities face significant costs to meet minimum safety and reliability standards for new distribution installations and these costs are clearly customer-related. In particular, Mr. Stowe cites minimum height requirements for distribution wires as well as size requirements for the wires that allow the wire to service more capacity than the customer for whom the system is being extended. Staff notes that he goes on to suggest that the cost incurred to comply with safety and reliability standards begins to outweigh the cost of meeting electrical demand. Staff considers IIEC's position unreasonable and contends that it would be presumptuous to argue that safety and reliability are new concerns for the regulatory process. Staff avers that these issues have existed since the electric industry began. Staff states further that utilities have incurred a variety of costs in the past to meet safety and reliability standards and presumably they will make significant future expenditures in these areas. Staff is not clear why Mr. Stowe considers expenditures on safety and reliability to be information that the Commission has not previously received or considered.

In addition, Staff states that it is difficult to conceive how safety and reliability are related to the number of customers on the system. The premise of the MDS system is that there are costs that pertain to connecting customers to the system, independent of the amount of demand. If the purpose of the distribution system were simply to connect customers, Staff submits that safety and reliability issues would then be a small fraction of their current levels. What creates significant safety and reliability concerns, Staff asserts, is the electricity that courses through the system.

IIEC’s position is also flawed, according to Staff, because it identifies a perceived customer component for a distribution system that is clearly related to customer demands. Staff contends that IIEC’s logic is comparable to arguing that costs associated with traditional customer-related components of the system, costs such as services and even meters, should be considered demand-related because a large 10 MW industrial customer would require a more costly service line and meter than a smaller customer. Nevertheless, Staff states that the costs of that service line and meter are considered customer-related because their primary purpose is to serve the individual customer. Similarly, Staff adds that the distribution system has the primary

purpose of meeting ratepayer demands and is appropriately considered demand-related.

3. AG's Position

The AG agrees with AIU that given the recent attention that the Commission has placed on rate design and cost of service issues for AIU's electric operations, it makes sense to have across-the-board increases in this case. Across-the-board increases, the AG continues, would avoid disparate bill impacts for different types of customers. AG witness Rubin states that a valid COSS is one piece of information the Commission should use in deciding each class's responsibility for any rate increase. But there is other important information that he believes the Commission also should rely on, including customer impact, the overall fairness of the result, rate continuity, gradualism, and other factors. Mr. Rubin contends that AIU's rate design and transition to fully unbundled rates has been exhaustively examined by the Commission over the past two years, and that transition process is still in progress. He maintains that it is reasonable, therefore, for the Commission to decide in this case that any rate increase or decrease should be borne by each customer class in equal proportion to the magnitude of the rate change itself.

The AG opposes IIEC's suggestion that rates be set based on a COSS that incorporates the MDS concept, either in this proceeding or any future proceeding. The AG points out that MDS affects the allocation of a significant amount of plant investment. In this case, the AG reports that IIEC's proposal will shift $54 million in rate base from the commercial and industrial classes to the residential class. For AmerenCILCO, the shift would move more than $16 million in rate base adjustments onto residential customers. This represents 5% of AmerenCILCO's total rate base. For AmerenCIPS, the shift would be $13 million (almost 3% of total rate base), and for AmerenIP the shift would be $25 million (almost 2% of total rate base).

The AG urges the Commission to reject the MDS proposal for various reasons. First, the AG states that IIEC witness Stowe makes several assumptions that are not supported by the evidence, including the submission of an alternative cost analysis that is based on hypothetical information that bears no relation to AIU's service territory. Second, the AG asserts that Mr. Stowe incorrectly assumes that the Commission's treatment of these issues has not been well informed. The AG argues that both of these assumptions are wrong. The AG relates that the Commission has consistently found that there is no customer-related component in these distribution system accounts. According to the AG, Illinois decisions rejecting MDS go back nearly 30 years, and include cases where the utility produced an MDS study that the Commission rejected. Moreover, the AG avers that the Commission's rejection of MDS has not been theoretical or based only on policy, as Mr. Stowe argues, but rather has been based on repeated findings that MDS analyses do not accurately reflect the cost of providing service to customers. (The AG references Docket Nos. 91-0335, 00-0802, and 05-0597 at page 49 of its Reply Brief.)

In response to IIEC's offer of evidence that the MDS exists, the AG states that IIEC simply relies on standards in the NESC that describe minimum standards for the construction of distribution systems. The AG also notes that Mr. Stowe did not actually conduct any analysis comparing the NESC minimum standards to AIU, but instead relied on "estimated customer and demand percentages" that he alleges are reasonable, based on studies performed for utilities in Missouri, Kansas, and Colorado. The AG asserts that the IIEC analysis is flawed in that it assumes the costs of meeting NESC minimum standards are (i) the same for utilities in different states and (ii) solely related to the number of customers served. In reality, the AG contends that the costs are based on factors completely unrelated to the number of customers served. These factors, the AG states further, are based on the assumption that customers will actually use electricity, causing the consideration of items such as the expected electricity consumption of customers; topography; population density; building type; the proximity of electrical facilities to railways, water and other natural or man-made features, etc. to be important factors.

AG witness Rubin points out that the NESC safety rules for the installation and maintenance of overhead supply lines consist of more than 120 pages and vary based on building height, use of land or water underneath the wires, etc. The AG asserts that IIEC's reliance on these standards is misguided. First, the AG argues that the different systems in Missouri, Kansas, and Colorado that IIEC relies on are not comparable to AIU's system. As an example, the AG states that in Colorado, the NESC standards require additional clearance at higher voltages because these systems are on a higher elevation than AIU's system. Second, the AG reports that there are highly disproportionate ranges for the customer related costs of each utility in the same FERC account; for instance, Account 366 ranges from 18%-94% and Account 367 ranges from 9%-79%. The AG maintains that Mr. Stowe's own data thus absolutely rebuts his testimony that it is reasonable to assume that an MDS study from one utility can be used as a proxy for another utility. Third, the AG alleges that IIEC does not establish that costs associated with satisfying NESC standards are related solely to the number of customers and not to the numerous other factors that affect the construction of distribution facilities. Fourth, the AG contends that IIEC does not establish why any minimum distribution system would be built in the absence of any electrical demand.

4. IIEC's Position

In support of its position that the COSS be used to set rates, IIEC points out that the Commission has recognized the importance of adhering to basic cost of service principles. According to IIEC, the primary reasons for using cost of service as the principal factor in revenue allocation/rate design are equity, cost-causation, appropriate price signals, conservation, and revenue stability. Cost-based rates, IIEC adds, are also essential to the development of competition.

IIEC states that the AIU electric COSS generally follow accepted cost of service principles. IIEC finds the studies to be generally sound and include many of the characteristics of a valid COSS. The studies, IIEC continues, recognize and separately

account for the multiple voltage levels at which AIU customers take service. IIEC witness Stowe, however, recommends one significant change to the AIU COSS--incorporation of the MDS concept.

With regard to the AIU gas COSS, IIEC witness Chalfant reviewed those studies and, while he disagrees with the use of the peak and average demand allocator, he does not propose any adjustment to the AIU studies, respecting use of that allocator. He concludes that the COSS demonstrate that industrial customers are subsidizing other AIU customer classes but that the use of the studies for revenue allocation and rate design purposes in these cases is sufficient to move rates toward cost. IIEC contends that the various rationales offered by AIU and Staff in support of an across-the-board approach for gas rates are not sufficient to justify abandonment of cost of service principles. IIEC asserts that AIU's reasons are basically non-cost arguments and many of them are totally unrelated to the provision of natural gas service. Those reasons include: (a) rate stability and continuity; (b) competition; (c) customer bill impact; (d) political environment; (e) AIU's electric rate increase; (f) gasoline prices; and (g) health care costs.

In response to these arguments, IIEC states that AIU has conveniently ignored the fact that rate stability and continuity and competition are enhanced by cost-based rates. Furthermore, IIEC insists that setting rates, as AIU proposes here, on the basis of what is politically correct is neither good public policy nor consistent with the other public policies and legislative priorities, such as the promotion of energy efficiency and demand response. Determining revenue allocations and setting rates on the basis of the increased cost of unrelated products and services, such as gasoline and health care is also not good public policy, according to IIEC. For example, customers who manage their electricity and gas costs through energy efficiency or demand response, possibly achieving savings as a result, may be confused to find their savings diminished by rates changed as a function of the cost of health care or some other product or service unrelated to electricity and natural gas service.

IIEC also suggests that perhaps too much emphasis is placed on rate impacts on DS-1 and DS-2 electric customers and that AIU and Staff have overlooked the fact that these customers have already been the beneficiaries of substantial rate mitigation. IIEC notes that assistance to small electric customers has come in the form of Docket No. 07-0165, Public Act 95-0481, and the Illinois Power Agency's efforts to purchase cheaper power for small customers. Large industrial customers, IIEC points out, are excluded from the benefits of the Illinois Power Agency's efforts.

While utilities normally have no financial stake in the revenue allocation method, IIEC suggests that in this proceeding AIU does; which may be influencing its endorsement of an across-the-board allocation method for electric rates. IIEC notes that AIU is proposing as a rate impact mitigation measure to cap DS-1 rates at an 8.5% increase in overall bundled rates for the first year. Recovery of any remaining allowed increase will begin in the thirteenth month following an order in this proceeding. Using AIU's proposed revenue requirement and across-the-board revenue allocation, IIEC

witness Stephens calculates that the voluntary rate cap would cost AmerenIP $31 million. Under AIU's proposed revenue requirement and rates based on a COSS, Mr. Stephens calculates that the voluntary rate cap would cost AmerenIP $67 million. He therefore concludes that use of the across-the-board allocation method allows AIU to recover an additional $36 million under the voluntary rate cap.

IIEC notes that no party to this proceeding elected to present a comprehensive COSS in response to AIU's COSS. Moreover, no party, other than IIEC, offers any critique of AIU's gas or electric COSS. Other than its proposal to modify the AIU electric COSS to include the MDS concept, IIEC contends that there should be no dispute over the appropriateness of the AIU cost studies in this case for allocation of gas and electric revenue requirements and rate design.

With respect to its suggestion to incorporate MDS into the electric COSS, IIEC has provided modified versions of the COSS to reflect the central idea behind the MDS concept. That idea, according to IIEC, is that there are delivery system costs that do not vary with customer demand, but rather are customer related and attributable to electric industry mandated safety and reliability requirements. By definition, the MDS system comprises every distribution component necessary to provide service, i.e., meters, services, secondary and primary wires, poles, substations, etc. The cost of the MDS, however, is only that portion of the total distribution cost the utility must incur to provide service to customers, it does not include costs specifically incurred to meet the peak demand of the customers. Mr. Stowe states that the latter costs are properly allocated on the basis of demand. But unless AIU's COSS are modified to reflect the MDS concept, IIEC maintains that AIU's COSS in this case tend to overstate the cost responsibility of relatively few large customers and understate the cost responsibility of the numerous small customers.

IIEC proposes that its modified versions of the AIU COSS be used for revenue allocation in this case. If, however, the Commission elects not to incorporate the MDS into the AIU electric studies in this proceeding, IIEC recommends that the Commission: (a) use the unmodified versions of the AIU studies for rate design and cost allocation purposes in this case, and (b) direct AIU to incorporate the MDS concept in its next electric delivery service rate case COSS.

In further support of the MDS, Mr. Stowe asserts that to serve customers--even small residential customers -- a utility can not install wires smaller than a certain mandated minimum size or hang wires on poles below a certain height. The applicable minimum size and height requirements are independent of the customer's maximum peak demand or energy usage. Minimum wire size and wire height are mandated by safety and reliability standards which are contained in the NESC. Under these standards, even if existing customer demand increases or decreases, Mr. Stowe testifies that the cost of meeting these NESC standards remains fixed. As an example, Mr. Stowe states that the cost of meeting code requirements for a customer with a peak demand of 3 kW is exactly the same as the cost for meeting the code requirements for a 150 kW or even a 1 MW customer. The components of the system that only just

conform to these safety and reliability standards comprise the MDS. The costs of these components represent the MDS costs. At the same time, he continues, if the system is expanded to meet additional peak demands, any costs above those associated with the minimum NESC requirements would be properly allocated on the basis of demand.

The NESC, Mr. Stowe argues, enables simple identification or MDS costs. He points out that the Commission has adopted the NESC standards (See 83 Ill. Adm. Code 305.20(b)), and Illinois utilities must comply with its mandates. The NESC specifies the minimum facilities and construction standards necessary for the safety of the public and utility employees in the installation, operation, or maintenance of electric supply and communication lines or their associated equipment. IIEC asserts that the cost of meeting these standards does not vary with the electrical demands or electrical usage of customers, but will vary based on the number of customers to be served by the electric utility.

In order to modify AIU's COSS to reflect the MDS concept in the absence of AIU specific data, Mr. Stowe used information from MDS studies of four companies which he either personally performed or reviewed during his employment with a public utility. Since the NESC standards apply equally to nearly every electric utility in the nation, Mr. Stowe concluded that it was reasonable to assume that the NESC standards are the same across utility service territories. Based upon this assumption and coupled with his experience in performing MDS studies for public utilities in other jurisdictions, he estimated applicable customer and demand percentages within the range of percentages determined by other utilities with urban operations, suburban operations, and rural operations similar to those of AIU. He also concluded that the total investment in rate base for these utilities was within the range of the total investment for AIU in this case, and that the average mix of primary and secondary distribution, as a percentage of total distribution plant, for his similar utilities was comparable to that of AIU in this case. With the use of these other four utilities' data, he determined the following demand and customer percentages: 84% demand and 16% customer for FERC Account 364 (Poles); 85% demand and 15% customer for FERC Account 365 (Overhead Wires); 39% demand and 61% customer for FERC Account 366 (Conduit); and 26% demand and 74% customer for FERC Account 367 (Underground Conductor). IIEC maintains that using Mr. Stowe's estimates of demand and customer percentages is better than making the de facto assumption that 100% of the subject costs are demand related and 0% are customer related. If the Commission concludes, however, that an Ameren-specific study is required, then IIEC suggests that AIU be directed to perform the necessary studies and present them in the next round of electric delivery service cases.

If the Commission adopts rates based on COSS, yet still has concerns about the impact on customers, IIEC proposes mitigation measures. For electric operations, IIEC offers two alternatives. Under the first alternative, rates for each class would move one-half of the way to cost of service. This approach reduces, but does not fully eliminate, rate subsidies provided or received by each class of customer. The second and final step to cost-based rates could be made in the next AIU electric delivery service rate

case or a specified period of time -- e.g., two years after rates take effect. The revenue allocations associated with such an approach for AmerenCILCO, AmerenCIPS, and AmerenIP under the original AIU COSS and IIEC's modified version of the AIU COSS are shown in IIEC Ex. 1.2. Under IIEC's second alternative for electric operations, the Commission could limit the increase to any class' distribution delivery service charges to not more than 25% above the respective utility's overall increase. For example, if AmerenIP were to be granted a 10% overall revenue increase in this case, no customer class would receive an increase greater than 35% (10% + 25%) in its distribution delivery service charges.

In the gas cases, IIEC recommends a revenue allocation that moves rates toward cost of service, but not completely to cost of service. IIEC states that revenue allocation in the gas cases was complicated by the proposed change in class structures for the gas operations of the three utilities. Because of the complications associated with changes in class structures, IIEC proposes a more moderate revenue allocation than suggested by the AIU gas operations COSS. This ensures that customers are not unreasonably impacted by the change in class definition. For AmerenCILCO, IIEC recommends a revenue allocation that still produces a decrease for GDS-1 - Residential (-4.5%), which is approximately the same as the system average decrease (-4.67%), a smaller than average decrease for Rate GDS-5 - Seasonal Delivery Service (-2%), and slightly larger than system average decreases for all of the remaining customer rate classes: GDS-4 (-11%), GDS-3 (-5.90%) and GDS-6 (-11%). For AmerenCIPS Gas, IIEC recommends a larger than average increase for GDS-1 -Residential (26.35%) and GDS-5 - Seasonal Delivery Service (26%) and a smaller than average increase for GDS-2 - Small General Service (17.15%) , GDS-3 -Intermediate General Services and GDS-4 - Large General Service (17.15%). For AmerenIP, IIEC recommends a larger than average percentage increase for GDS-1 - Residential (48%), GDS-3 - Intermediate General Service (48%), and GDS-5 - Seasonal Delivery Services (55%) and smaller than average percentage increases for GDS-2 - Small General Service (37.07%) and GDS-4 - Large General Service (37.24%).

With regard to AIU's proposal to maintain uniformity in certain charges among the three electric utilities, IIEC does not oppose uniform charges per se. IIEC observes that these charges were set on a uniform basis in AIU's last delivery service cases using a combination of embedded costs and replacement or incremental costs. IIEC reports that AIU did not supplant those charges with new cost-based charges. IIEC contends that AIU increases its costs by an escalation factor that is both illogical and unsupported in the record. The proposed charges were escalated on a ratio of the overall increase in delivery service revenues for all three AIU operating companies. According to IIEC, the overall increase ratio of 27% is a function of AIU’s proposed revenue allocations and is based on increases to some cost items that have nothing to do with the customer charges, such as electric poles. The escalation factor for the customer charge results in a 27% increase. IIEC argues that there is no basis on which to conclude that the real underlying cost components of the customer charges, as determined in the last AIU delivery service rate cases, have increased by 27% in the two years between the 2004 test year in the last case, and the 2006 test year used in this case. IIEC states that a

similar concept holds true for transformation charges and reactive demand charges. In the absence of a valid cost basis for a change in the present customer, meter, transformation, and reactive demand charges, IIEC urges the Commission to retain the current charges.

5. Commercial Group's Position

The Commercial Group endorses the use of AIU's COSS, with the electric COSS modified to reflect the MDS concept. Using AIU's electric COSS, the Commercial Group determined the degree to which certain classes are currently subsidizing other classes. The following table depicts the relative rate of return for each electric class of customers for each utility. The Commercial Group submits that a relative rate of return greater than 1.0 indicates that a customer class is providing subsidies to other classes, while a relative rate of return less than 1.0 indicates that a customer class is receiving subsidies from other classes.

	AmerenCILCO	AmerenCIPS	AmerenIP
DS-1	0.82	0.62	0.26
DS-2	1.39	1.93	2.91
DS-3a	1.76	2.10	1.24
DS-3b	1.86	1.87	2.18
DS-4	0.77	0.59	1.62
DS-5	0.84	1.20	2.38

The Commercial Group argues that all AIU DS-2 and DS-3 customers are currently paying more than their respective cost of service. The Commercial Group also notes that the DS-3 class includes elementary schools while the DS-4 class includes high schools and colleges. The Commercial Group maintains that it is not fair for commercial and industrial customers, schools, and colleges to subsidize other customers.

In addition, the Commercial Group asserts that AIU has an incentive to propose an across-the-board electric rate increase in light of its voluntary rate cap proposal. Mr. Stephens, the Commercial Group states, correctly points out that AIU has a $36 million incentive to propose an across-the-board increase. In effect, AIU's other customers are being asked to help pay for AIU's voluntary rate cap.

The Commercial Group is also under the impression that the Commission, in AIU's last rate case, directed AIU to file rates based on cost in its next rate case:

> [C]ircumstances in this case lead us to believe that no customer class here should subsidize the delivery services rates of another. The

> Commission directs the Ameren companies, in compliance filings, to file tariffs based on cost of service using the NCP allocation method. (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 175)

The Commercial Group states that AIU filed COSS' in this case, although it did not file tariffs based on the COSS'. Mr. Baudino for the Commercial Group reviewed these studies and found them generally reliable for setting class rates.

In response to AIU's comment in its Initial Brief that it worked with the parties in an effort to address their concerns with its across-the-board proposal, the Commercial Group states that it is not sure what AIU means by this remark. The Commercial Group indicates that AIU did not approach it to discuss its concern of having to pay bills that are higher than cost. Nor does the Commercial Group understand AIU's reference in its Initial Brief to higher gasoline prices, higher energy bills, and higher health care costs as reasons for across-the-board rate increases. The Commercial Group asserts that these may be good reasons for keeping AIU's revenue increase as low as possible but not for increasing the subsidization of some classes by others.

The Commercial Group also objects to Staff's proposal for setting rates based on which customer groups can more easily absorb a greater bill increase. It is unclear to the Commercial Group how a class' relative ability to absorb rate increases could be measured in a fair, meaningful, and transparent manner. Regardless of the manner, the Commercial Group maintains that the ability to absorb rate increases (or willingness and ability to organize and advocate) is not a fair, objective way to set rates; cost is the fairest basis for setting rates.

6. Commission Conclusion

In determining whether to adopt an across-the-board rate increase or one based on AIU's COSS, the Commission notes that AIU, Staff, the AG, IIEC, and the Commercial Group have made extensive arguments both for and against the two proposals. Generally, the Commission prefers to set rates as close to the cost of service as is reasonably possible and/or appropriate. To do so, the Commission must first have an accurate idea of what the cost of serving each customer class is in each service area. AIU included with its initial rate filing COSS for its gas and electric operations. Although AIU supports an across-the-board rate increase, its COSS have been entered into the record via the granting of a June 6, 2008 IIEC motion. No party questions the validity of AIU's COSS, although IIEC and the Commercial Group would like the electric COSS to be modified to reflect the MDS concept.

IIEC and the Commercial Group express frustration with the subsidization of smaller customers by larger customers under current electric rates. While they understand the Commission's conclusions in Docket No. 07-0165 that led to the current rate structure, they do not believe that it is fair for larger customers, who are experiencing the same economic uncertainties as smaller customers, to be required to help support smaller customers. The Commission understands this frustration, but in

light of the customer impacts that led to the rate redesign in Docket No. 07-0165, finds itself in a difficult situation. Given that the rate design resulting from Docket No. 07-0165 has only been in effect since January 1, 2008, the Commission is reluctant to return to full cost based rates after less than one year. The rate shock that would result from returning to full cost based rates would likely lead to another redesign docket. In order to mitigate the impact of the rate increase approved in this proceeding and avoid renewed rate shock, the Commission believes that it is more appropriate at this time to, generally, increase rates on an across-the-board basis. The Commission certainly does not mean to suggest by this decision that cost based rates have fallen out of favor. Indeed, cost based rates, as we affirmed in our recent decision in Docket No. 07-0566, continue to be the Commission's preferred rate design methodology. That said, for purposes of this proceeding and based on this record the Commission concludes that adoption of an across-the-board increase is the most prudent and reasonable methodology that will serve to ease rate impacts occurring due to the continued transition from the end of the rate freeze.

Since the Commission is not adopting rates based on AIU's COSS, it need not address the proposal that the COSS be revised to reflect the MDS concept. Nevertheless, the Commission feels compelled to mention that using cost data from other utilities and applying that data to AIU, as IIEC does, is of little value to the Commission. As noted by AIU and other parties, significant differences exist between AIU and certain of the utilities that IIEC chose to use data from and apply to AIU. As for requiring AIU to submit COSS incorporating MDS in its next rate cases, the Commission notes AIU's objection that it not be required to do so unless the Commission intends to adopt the MDS concept in setting rates. While IIEC's discussion of the MDS concept presented some interesting ideas to consider, the Commission is not prepared to conclude here that it will implement MDS in AIU's next rate cases. Therefore, the Commission will not require ratepayers to pay the cost of preparing a COSS incorporating the MDS concept for AIU's next rate cases. This does not mean to suggest, however, that other parties should not feel free to propose COSS reflecting the MDS concept.

As noted above, AIU determined that for the purposes of this proceeding to no longer seek uniformity and instead agreed to adjust the DS-1 customer, meter, and distribution delivery charges by a level equal to the average change in residential delivery service revenue for each of the three utilities. The Commission understands that Staff and the AG agree with the changes on this issue. The Commission finds AIU's proposal regarding DS-1 reasonable and approves it. In the future, however, the Commission will be interested in returning to uniform customer, meter, and distribution delivery charges among the customers of the three utilities to the extent that doing so is prudent.

For the DS-2, DS-3, and DS-4 classes, AIU also proposes to maintain uniform meter and customer charges across the three utilities. AIU also proposes to maintain uniform transformation (for both DS-3 and DS-4) and reactive demand (DS-4 only) charges. AIU states that the distribution delivery charge is proposed to "float" to recover

the remaining revenue requirement targeted for each class. AIU believes that this proposal will facilitate service to customers, or potential customers, taking electric service from more than one of the utilities. The Commission recognizes that there are objections to at least portions of this AIU proposal, but nevertheless finds it reasonable and agrees that it will likely facilitate service to larger customers. The Commission therefore approves this AIU proposal.

With regard to the Commercial Group's citation to page 175 of the Order in Docket Nos. 06-0070/06-0071/06-0072 (Cons.) and its discussion of cost based rates, it appears that the Commercial Group misunderstands what is meant by a compliance filing. The compliance filing in that context referred to AIU's tariffs implementing the conclusions in that Order and filed within days of the entry of that Order. The language cited by the Commercial Group was not referring to AIU's next rate cases.

B. COSS in Next Rate Cases

Staff recommends that AIU propose gas and electric rates in the next rate cases based on cost of service. AIU does not object to doing so but indicates that it may also propose rates using an across-the-board approach or some other hybrid method. AIU explains that it wishes to preserve its options in case it does not believe, under the circumstances in the next cases, that strict adherence to cost of service is appropriate. Staff agrees that there is no way of predicting the future and what conditions may exist, and understands AIU's caveat to leave its options open to an alternative rate design dependent on future conditions. IIEC and the Commercial Group support the filing of COSS in AIU's next rate cases, but add that the electric COSS should incorporate the MDS concept. LGI recommends that AIU's next rate filings include a detailed COSS showing a lighting cost of service analysis for AIU identifying lighting fixture costs as well as a detailed street light rate design study to determine cost-based lighting fixture charges. If AIU is to file new COSS in its next rate cases, Grain and Feed Association of Illinois ("GFA") would like the studies to evaluate and address the characteristics of seasonal users in general and, in particular, grain dryers. AIU objects to conducting studies incorporating GFA's proposal.

AIU is already required to provide a COSS for each utility pursuant to Part 285. The Commission anticipates that AIU will comply with this requirement and provide COSS in its next rate case filings. The Commission 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. In considering a move towards rates based on the cost of service, AIU should take into account alternative rate structures for the all-electric residential customer sub-class that would incorporate the effect of innovative market-based dynamic or real-time pricing rate structures for retail all-electric customers. Market-based dynamic prices may have the overall effect of reducing the electric bills of all-electric classes of customers while at the same time ending the explicit subsidy that was designed to accomplish the same end. (See Docket No. 07-0165, Order at 25-28 (Oct. 11, 2007); see generally, Order on Rehearing (Oct. 29, 2007). In times of rapidly rising energy costs, the Commission needs to be able to

consider all options available to it to restrain rate shock while simultaneously setting rates as close as possible to cost. An analysis of the effect of dynamic market-based prices for the all-electric sub-class of residential customers would give the Commission valuable insight as to its potential benefits as the utility tries to meet those important, and some times mutually exclusive, objectives in the next rate case. In its cost of service analysis, AIU's electric utilities should develop a separate sub-class for the residential space-heat customers and consider the use of a straight-fixed-variable rate design for this sub-class of customers if a dynamic pricing rate design utilizing market-based rates can be shown to be beneficial. Whether AIU proposes alternative rates based on some other approach is up to AIU for the reasons discussed above. However, having cost-based rates with which to compare against alternative approaches will be instructive. As noted earlier, the Commission will not be requiring AIU to incorporate the MDS concept in its next electric COSS. The Commission will, however, require AIU to analyze the cost of lighting service in each of the utility's electric service areas and develop cost-based rates for lighting fixture charges, as proposed by LGI. AIU shall also analyze the cost of serving seasonal gas users as proposed by GFA. The arguments of LGI and GFA both give the Commission reason to further consider their respective positions. AIU's rate filings, however, need not reflect adoption of the lighting and seasonal user analyses. These analyses simply need to be available for the parties and Commission to consider.

IX. RATE DESIGN/TARIFFS TERMS AND CONDITIONS

The above discussion on how to allocate costs among the classes of electric and gas customers is but one component of rate design. Rate design, in the parlance of the Commission, also encompasses the terms and conditions of service in a utility's tariffs. Over the course of this proceeding, parties raised several issues and presented arguments concerning the terms and conditions of service. Some of these issues have been resolved, while others remain contested.

A. Resolved Gas and Electric Issues

1. Budget Billing Plan Tariffs

Staff witness Harden recommended that AIU provide more specific language concerning the methodology used in its budget billing plan regarding over or under recovery of customer revenue. In response, AIU witness Jones proposed revised language that (a) reinstates the "annual settle-up" (i.e., lump-sum settlement) language in existing tariffs and (b) provides flexibility for AIU to offer a second choice to customers to smooth any annual settlement amount over the next 12 months. Ms. Harden agrees with AIU's revised language for both the gas and electric tariffs. The Commission finds the revised language appropriate and directs that it be used.

2. Refundable Deposits for Line Extensions

Staff witness Lounsberry raised a concern regarding AIU's proposed tariff language concerning refundable deposits under AIU's Standards and Qualifications for Gas Service. He believed that the language could be interpreted in a manner inconsistent with 83 Ill. Adm. Code 500, "Standards of Service for Gas Utilities." In response to Staff data request ENG 2.202, AIU witness Warwick provided alternative language alleviating Mr. Lounsberry's concerns. The Commission finds the alternative language reasonable and directs that it be used.

Similarly, Staff witness Rockrohr raised a concern regarding AIU's proposed tariff language concerning refundable deposits under AIU's Standards and Qualifications for Electric Service. He believed that the language could be interpreted to mean that AIU would have sole discretion to determine the period of time over which an applicant who makes a refundable deposit would qualify for a refund, which is contrary to Section 410.410. In response, AIU witness Jones provided alternative language clarifying that customers will always have a cash deposit option available. This language is acceptable to Mr. Rockrohr. The Commission concurs and directs that the alternative language be used in AIU's compliance filing.

B. Resolved Gas Issues

1. Uniform Gas Tariff Language

AIU submitted an entirely new tariff book for each of the three gas utilities. Many of the terms and condition are the same as those in the existing tariffs, but have been written/presented differently in order to make the three companies' tariffs more uniform. AIU describes the proposed changes in its Initial Brief at pages 324 through 327. Staff agrees that creating more uniform gas tariffs is desirable and recommends that the Commission approve the revisions. The Commission concurs and directs AIU to reflect the changes in its compliance filings in this proceeding.

2. Renaming of Certain Gas Customer Classes

AIU proposes to rename its gas customer classes as follows in order to conform to its electric customer classes:

AmerenCILCO

Present Rate Classification	Proposed
Rate 510 – Residential Gas Service	GDS-1
Rate 550 – Small General Gas Service	GDS-2
Rate 600 – General Gas Service	GDS-3
Rate 600 – Minimal Winter Use Gas Service	GDS-5
Rate 650 – Intermediate General Gas Service	GDS-4

Rate 700 – Large General Gas Service	GDS-6
Rate 800 – Contract Service	GDS-7

AmerenCIPS and AmerenCIPS Metro-East

Present Rate Classification	Proposed
Rate 1 – Residential Service	GDS-1
Rate 2 – General Delivery Service (small meter < 700 cubic feet per hour ("cfh"))	GDS-2
Rate 2 – General Delivery Service (large meter > 700 cfh)	GDS-3
Rate 3 – Large Use Firm Delivery Service	GDS-4
Rate 3 – Minimal Winter Use Delivery Service	GDS-5
Rate 4 – Large Use Inadequate Capacity Delivery Service	GDS-4
Rate 4 – Minimal Winter Use Delivery Service	GDS-5
Rate 5 – Special Contract Service	GDS-7

AmerenIP

Present Rate Classification	Proposed
Rate 51 – Residential Gas Service	GDS-1
Rate 63 – Small Volume Firm Gas Service	GDS-2
Rate 64 – Intermediate Volume Firm Gas Service	GDS-3
Rate 65 – Large Volume Firm Gas Service	GDS-4
Rate 66 – Seasonal Gas Service	GDS-5
Rate 76 – Transportation of Customer Owned Gas Service	GDS-1-5
Rate 90 – Contract Service	GDS-7

Staff accepts the proposed renaming of the gas customer classes as long as it does not result in unequal bill impacts on individual gas customers. The Commission finds the proposal to rename the customer classes reasonable and is aware of no unequal bill impact on any customers; therefore the renaming of the classes should be reflected in the compliance filings.

3. Customer Charges and Metering Differentials

AIU initially proposed to change all customer charges by an across-the-board percentage except the differential between the customer charges for sales customers and the customer charges for transportation customers that accounts for the added costs of daily metering. AIU's proposal also included the requirement of daily metering service and the imposition of such a differential for the first time for AmerenCILCO's Rider T customers. Staff witnesses Sackett and Harden objected to the exceptions to the across-the-board change. Mr. Sackett testified that the disproportionate changes would be a barrier to transportation customers. Ms. Harden objected because the

proposal deviates from the across-the-board change and would cause a higher level of bill impacts for transportation customers. AIU witness Warwick accepted this, removed the AmerenCILCO differential, and changed the customer charges for each Local Distribution Company ("LDC") by the across-the-board percentage. Staff finds these changes acceptable and the Commission concurs with these changes. The resolution of this issue between AIU and Staff should be reflected in AIU's compliance filing to the extent not otherwise affected by the conclusions below.

4. Use of PGA in Cashout Mechanisms

Initially, AIU proposed to cashout daily imbalances between nominations and usage for gas transportation customers at the higher of the Chicago City gate price or the PGA and monthly imbalances at the higher of the Average Chicago City gate price or the PGA. Staff witness Sackett objected to this because the Chicago City gate price reflects the market and no other major LDCs in Illinois have the PGA in their cashout mechanism. AIU witness Glaeser removed the proposal. The current proposal is for the Chicago City gate to be the only daily cashout price. AIU has also removed its proposal for a monthly cashout. Staff agrees with this proposal. CNE-Gas supports these changes as well. The Commission finds the cashout mechanism acceptable and directs that it reflected in the compliance filing.

5. Curtailment Language

Staff identified a drafting error regarding the proposed Curtailment Plan – wherein transportation customers were to be completely curtailed before any system supply customer. AIU addressed this error and indicates that it is not its intent to confiscate gas supply from a transportation customer and supply it to a PGA customer of the same type in the event of a system curtailment. AIU states that curtailments will take place on a customer service level and not by the type of service (Rider T or Rider S) the customer is utilizing.

Staff also recommended that AIU adopt a blend of the current AmerenCILCO and AmerenIP curtailment plans. AIU contends that doing so is not feasible. AIU witness Glaeser explained that the Curtailment Plan would only be initiated in the most severe circumstances when it is imperative that customers reduce load to enable AIU to serve the residential customers and human need providers. AIU stated that Staff's recommendation is a complicated scheme that would not be workable in an expeditious manner during a system emergency. Staff later accepted AIU's explanation.

In response to CNE-Gas' comment that AIU should only curtail deliveries within a particular customer class, without regard to whether a customer is a firm transportation or firm sales customer, AIU stated that this is exactly how the Curtailment Plan is written and intended to operate. Mr. Glaeser explained that the first category of Curtailment is "Category 1: Customers taking service under Rates GBS-4, 5, 6, and 7 except those Customers identified under Category 3" and that the curtailment language is defined by

rate category and, again, not whether the customer is taking service under Rider T or Rider S.

Staff witness Sackett objected further to AIU's proposed curtailment language because although AIU provided a rationale for four of the reasons that a Critical Day may be declared, it also added a fifth “catch-all” reason. Initially, AIU had proposed to add language under Rider T to allow the declaration of a Critical Day for any “other market condition which may warrant such action by [AIU].” Later, Mr. Glaeser offered to revise the language under the Critical Day definition to reflect the purpose of declaring a Critical Day. The Critical Day definition was revised by removing “market” prior to “conditions” and qualifying that action may only be taken due to conditions which “jeopardize the system integrity and/or system reliability.” Staff found this change acceptable.

The Commission finds the resolution of the curtailment language issues reasonable and directs that AIU's compliance filing reflect the resolution.

6. Small Volumetric Distribution Charge

AIU recommended eliminating the Small Volumetric Distribution Charges for AmerenCILCO GDS-4 and GDS-6, and AmerenIP GDS-4. Staff witness Harden did not agree with this due to the unequal bill impacts for individual gas customers that could result from this change. AIU has agreed to maintain the Small Volumetric Distribution Charge for these rate classes. The Commission concurs that doing so is appropriate.

7. Standard Information Provided with Customer Usage History

In response to an issue raised by CNE-Gas, AIU agrees to provide with usage history requests (a) the customer's service classification and rider(s), (b) the customer's maximum daily contract quantity, (c) if applicable, the customer's bank volume, and (d) if applicable, the customer's gas main maximum allowable operating pressure. The Commission finds that doing so is reasonable and directs provisioning of this information be reflected in AIU's compliance filings.

8. Reconnect Charge

AIU witness Warwick proposes to set the gas Reconnect Charge at $15.00 during regular working hours and at $50.00 outside of regular working hours for each of the three utilities. The Reconnect Charge is currently $55.00 during regular working hours and $100 outside of regular working hours at AmerenCIPS, $25 or actual cost at AmerenCILCO, and $15.00 during regular working hours and $25 outside of regular working hours for AmerenIP. Staff recommends approval of the uniform Reconnect Charge changes as a reasonable change. The Commission concurs and approves the change.

9. Dishonored Check Charge

AIU witness Warwick proposes to set the Dishonored Check Charge at $15.00 for each of the three utilities on any negotiable instrument returned by a bank, savings institution, or other institution. The Dishonored Check Charge is currently $15.00 at AmerenCIPS and $10.00 at AmerenCILCO and AmerenIP. Staff recommends approval of the uniform Dishonored Check Charge change, noting that it is below the charge at many other Illinois utilities. The Commission finds the $15.00 Dishonored Check Charge reasonable and approves of the change.

10. Footage Allowance for Service Connections

AIU witness Warwick proposes to conform all of AIU's gas tariff language regarding allowances for service connections to the language contained in the Joint Agreement of the Parties, attached as the Appendix to the Commission's Order in Docket No. 03-0767. In that proceeding, all parties reached an agreement that the free footage allowance for service connections in Illinois should be 60 feet of gas pipe. Staff witness Harden finds AIU's proposal acceptable. Consistent with its findings in Docket No. 03-0767, the Commission approves of this change.

11. Group Balancing Service for AmerenCILCO

AIU witness Glaeser explains that a key provision in the proposed services allows for Group Balancing under Rider G, which is a new service for transportation customers on the AmerenCILCO system. Group Balancing is already available to AmerenIP and AmerenCIPS transportation customers. The service provides the transportation customer and/or its marketer with an opportunity to request that its accounts be combined with two or more accounts on the same interstate pipeline for nominating and balancing purposes. Transportation customers located in a city that is served by multiple interstate pipelines, as identified on the AIU web page under Unbundled Services Management System ("USMS"), will be allowed to balance nominations across those specific multiple pipelines. Additionally, this service allows the Group Manager to manage a group of customer accounts as a single load rather than by individual accounts, and provides a netting mechanism for mitigating imbalances, wherein the daily over-deliveries for one customer can offset the under-deliveries for another customer. This offsetting arrangement aids the Group Manager in keeping daily imbalances to a minimum. The larger the marketer's customer group becomes under Group Balancing, the greater the netting effect which improves daily imbalance performance. The Commission considers the provisioning of Group Balancing for AmerenCILCO transportation customers appropriate and approves of its implementation.

12. Consolidation of PGA Rates

AIU witness Glaeser proposes that the AmerenCIPS PGA and the AmerenCIPS Metro-East PGA be consolidated into a single PGA rate. According to Mr. Glaeser,

natural gas prices have been more volatile since the winter of 2000-2001. If consolidated, he states that the AmerenCIPS Metro-East customers would be part of a larger service area and a more stable PGA rate could be provided because of expanded hedging opportunities. Mr. Glaeser explains that the AmerenCIPS strategy is to have approximately 60-75% of a normal winter's demand hedged through a combination of price hedge protection and storage withdrawals. He asserts that this strategy works well in a large system that has a large number of baseload transactions that can be efficiently price hedged. This same strategy, however, becomes constrained in a small system with limited baseload transactions where one or two hedging transactions determine the PGA for the entire winter heating season. Mr. Glaeser further testifies that if the Commission grants this proposal, AIU would be willing to work with Staff to develop a mechanism to ensure that the AmerenCIPS and AmerenCIPS Metro-East customers would be charged or credited with respect to the balance of any over- or under-recovered costs existing at the implementation date.

Based on these potential benefits to AmerenCIPS Metro-East customers, and given Mr. Glaeser's agreement to work with Staff while converting to a single PGA rate, Staff does not oppose the consolidation of the AmerenCIPS and AmerenCIPS Metro-East PGA rates into a single PGA rate. If the Commission approves AIU's proposal to consolidate the PGAs, Staff recommends that the Commission order AmerenCIPS to submit a monthly report to the Commission's Bureau of Public Utilities, for one year following the date of the order in this proceeding, estimating the PGA rates applicable to AmerenCIPS and the AmerenCIPS Metro-East territory as if no consolidation had been approved. AIU does not object to submission of monthly report as described by Staff. The Commission finds the proposals reasonable and directs that they be reflected in AmerenCIPS' compliance filing.

13. Ameren CIPS Rate 2

For AmerenCIPS and AmerenCIPS Metro-East, AIU witness Warwick proposes splitting existing Rate 2 -General Delivery Service into two new rate classes: GDS-2, for small meters (Meter A) and usage less than 700 cfh, and GDS-3, for large meters (Meter B) and usage greater than 700 cfh. Staff witness Harden does not oppose this proposal since it would not result in unequal bill impacts for individual gas customers. The Commission finds the proposal reasonable and approves it.

14. AmerenCIPS Rate 4

AIU inadvertently omitted certain tariff language it had intended to retain from the current AmerenCIPS Rate 4 – Inadequate Capacity System Gas Service. The language is currently in the existing AmerenCIPS tariff and it is appropriate to maintain the same language in the proposed tariffs related to this case. Staff supports the revision of the tariff to include the language in question. The Commission concurs with the revised language and directs that it be used.

15. AmerenIP Service Activation Fee

AIU witness Warwick proposes to eliminate the gas Service Activation Fee for AmerenIP, as neither AmerenCIPS nor AmerenCILCO have a similar provision. AmerenIP's Service Activation Fee is $10.00 when a customer requests service under Service Classifications 51, 63, or 64. If the service activation requires lighting, relighting, or inspection of appliances, the charge is $25.00. Since AmerenIP has not shown a need for the charge and since AIU is focusing on uniformity in the instant proceeding, Staff witness Harden agrees with AIU that elimination of the Service Activation Fee from AmerenIP's tariffs is appropriate. The Commission concurs and directs that this change be reflected in AmerenIP's compliance filing.

16. AmerenIP Rates 4 and 5

AIU witness Warwick proposed to eliminate the AmerenIP Facilities Charge presently in Rates 65 and 66. Staff witness Harden initially opposed this change and proposed that an across-the-board increase be applied to each rate without eliminating any individual rate elements, because unequal bill impacts may occur. In response, Mr. Warwick stated that this proposed revision would not result in unequal customer bill impacts. To further the argument, he presented an example calculation in which he increased the Facilities Charges by the overall percentage increase, with some rounding, and then merged the resulting charge into the proposed Customer Charges. In the example, the resulting value is the same whether the Facilities Charge is a separate charge or rolled up with the Customer Charge. Therefore, there is not an unequal bill impact. AIU contended that the resulting charge becomes more straightforward to the customer by eliminating unnecessary line item charges. AIU stated further that this is another area where it can move towards tariff conformance with no adverse customer impact. Staff agreed to merge the AmerenIP Facilities Charges for GDS-4, GDS-5, and Rider T into the applicable Customer Charges. The Commission approves of this proposal.

17. Elimination of AmerenIP's Rider H

AmerenIP proposes to eliminate its Rider H – Adjustment for Pipeline Transition Surcharge since it has not been used in several years. Staff witness Harden agrees that Rider H should be eliminated from the AmerenIP tariffs. The Commission finds this proposal reasonable and approves it.

C. Resolved Electric Issues

1. Customer and Meter Charge

AIU has a three-part residential electric rate consisting of a customer charge, a meter charge, and a distribution charge. The current customer charge and meter charge are the same among the three utilities. AIU had initially proposed to increase the customer and meter charges by 27% for all three, which is AIU's proposed system-

wide approximate average increase. Because of the impact on residential bills, the AG and Staff objected to AIU's proposal and recommended that AIU at least temporarily abandon the notion of uniform customer and meter charges. AIU now agrees and favors an approach similar to that of the AG and Staff. Pursuant to this approach, AIU will increase customer and meter charges by a level equal to the average change in residential delivery service revenue for each of the three electric utilities. The Commission finds that the AG and Staff approach is reasonable for purposes of this proceeding and approves it, however, the Commission directs AIU and Staff to review the issue of uniform customer and meter charges among the three utilities in their next electric rate cases.

2. Supply Cost Adjustments

The components that make up AIU's Supply Cost Adjustment ("SCA") are as follows: the Supply Procurement Adjustment, an Uncollectibles Adjustment, and a cash working capital adjustment. The Commission has directed AIU to update these costs and/or factors in delivery services rate case proceedings.

a. Supply Procurement Adjustment Amortization Period

AIU states that the Supply Procurement Adjustment is intended to compensate each utility for all direct and indirect costs of procuring and administering power and energy supply for all customers, other than amounts recovered in other charges to customers receiving power and energy service from AIU. According to AIU, these costs consist of expenses such as professional fees, costs of engineering, supervision, insurance, payments for injury and damage awards, taxes, licenses, and any other A&G expense not already included in the cost of power and energy service.

AIU and Staff agree that the correct ongoing costs to be recovered through the Supply Procurement Adjustment is $1,057,003 and the amount to be amortized over the life of these rates is $1,415,011. AIU states that it and Staff agree on the amount of the adjustment, and agree that the amortization period for the amortized portion of the costs should be consistent with the amortization period approved by the Commission in this case for electric rate case expense. AIU says the parties only disagree with whether such amortization should be based on two years or three years.

The Commission has determined the amortization period for rate case expense elsewhere in this Order. It appears that there is no other decision that the Commission must make with regard to this issue.

b. Uncollectible Adjustment

AIU witness Jones presented a chart in direct testimony showing proposed Uncollectibles Adjustment factors by rate class, which are a subset of the SCA contained within Rider PER (AIU's tariff governing prices and cost recovery for fixed price power supply service). Staff witness Ebrey objects to a portion of the calculation

proposed by AIU pertaining to write-offs for combination (both gas and electric) customers, and recommends that write-offs be allocated based on the relative gas versus electric revenues for combination customers. AIU adjusted its methodology for development of the class specific uncollectibles factors based on Ms. Ebrey's recommendation in her rebuttal testimony, and thus the issue is no longer contested. AIU states that now, only the total level of uncollectible account expense is at issue. The updated Uncollectibles Adjustment factors, taking into account the adjustment proposed by Ms. Ebrey and the total level of uncollectible account expense proposed by Mr. Stafford, are presented in AIU's Initial Brief. AIU says that if the Commission approves overall uncollectibles rates different from those provided in Mr. Stafford's rebuttal, the class level uncollectibles factors should be updated to match the approved overall uncollectibles rate.

The Commission has determined the uncollectibles issue elsewhere in this Order. AIU is directed to update the uncollectibles factors consistent with the Commission's conclusions when it makes its compliance filing at the conclusion of this proceeding. Based upon the Commission's decision to adopt AIU's three-year average for uncollectibles, the approved uncollectibles factor for AmerenCILCO is 0.582%, for AmerenCIPS is 0.569%, and for AmerenIP is 0.541% as shown on Ameren Ex. 19.4.

c. CWC Adjustment

According to AIU, the purpose of the CWC Adjustment is the equitable recovery of the time value of expenses incurred to purchase power and energy for customers in a manner that recognizes the time lag between the incurrence of these expenses and the revenue stream or receipts from customers who pay for said power and energy. AIU's proposed CWC Adjustment is 0.7986%, which has increased from 0.308%.

AIU claims the CWC associated with the power supply should be based on the calculations shown on Ameren Ex. 3.16E for each of the utilities. As discussed above in this Order, Staff witness Kahle recommends that AIU receive preferential treatment on the timing of payments from affiliated companies, in order to offset the shorter lead time in which AIU has to pay suppliers for electricity purchases, due to AIU's current credit situation. AIU argues that Mr. Kahle's position should be rejected because it conflicts with the Commission's rules designed to protect against preferential treatment between affiliated companies.

The Commission has made its decision regarding CWC elsewhere in this Order. When it makes its compliance filing at the conclusion of this proceeding, AIU is directed to make any changes to its SCA to reflect the Commission's decision regarding CWC. The Commission approves a CWC Adjustment factor of 0.7986% for use in Rider PER.

D. Contested Gas Issues

1. Gas Bank Sizing and Daily Balancing Tolerances

a. AIU's Position

In an effort to bring standardization and uniformity to gas transportation services across the three utilities, AIU has requested approval to unite all transportation services into one new rider, Rider T--Gas Transportation Service, applicable to each utility. In the process of reforming the transportation services to bring about standardization, AIU has also updated the tariffs to meet modern system goals and requirements. Central to the Rider T proposal are the policies presented with regard to banking services and imbalance tolerances designed by AIU to meet the necessities of modern operating and market conditions.

i. Policy Considerations

To understand the relevance of its banking services proposal, AIU points to the policy drivers behind the banking services and imbalance tolerance provisions, and the overall context of banking services within the Rider T framework. AIU asserts that the need for modified banking services and tolerance levels is driven by:

- Gas price volatility, which exacerbates the potential gaming opportunities and unduly exposes sales customers to cost transfers;
- Pipeline tariff restrictions, which limit the gas utilities' flexibility; and
- Pipeline capacity constraints, which means there is not the means by which to access additional gas supply.

AIU asserts that extreme price volatility in the North American natural gas markets since the winter of 2000/2001 and growing interstate pipeline capacity constraints have fundamentally changed the nature of the natural gas industry. AIU contends that the flexible transportation services it currently offers were developed years ago during a period of stable gas prices and excess and unconstrained interstate pipeline capacity in the Midwest, conditions that no longer exist today. Certain of AIU's existing transportation services include monthly balancing. AIU asserts that monthly balancing was acceptable when gas prices were stable at $2 per MMBtu for years on end, but becomes very problematic when gas prices swing up to $1 per MMBtu from day to day and can reach $14 per MMBtu during peak periods.

Monthly balancing, AIU continues, creates opportunities for gas suppliers to exploit short-term price swings. AIU explains that monthly balancing in volatile gas markets gives transporters and marketers an incentive to “short” (under-deliver gas supply compared to customer demand) the LDC system on days when gas prices spike to high levels and “go long” (over deliver gas supply compared to customer demand) on days when gas prices drop to low levels, while staying roughly in balance by the end of the month. AIU witness Glaeser testifies that this manner of market arbitrage raises

AIU's costs. Since the transportation customer's demand still exists while its marketer is "shorting" the system, he explains that the LDC must still meet the overall demand of the system by delivering additional gas supplies from its suppliers and withdrawing additional gas from leased and on-system storage resources. In other words, the LDC must purchase additional gas supplies at potentially higher market prices to make up for marketers "shorting" the system. This in turn, Mr. Glaeser reports, may directly impact the sales customers, since the cost of the incremental supplies and storage withdrawals are included in the PGA rates which are paid for by the sales customers and not the transportation customers or their marketers. The inverse situation is also problematic, where daily gas prices drop to low levels and a marketer will "go-long" or over-deliver compared to its customer's demand which, in turn, makes less room for the LDC to acquire gas supply during low priced periods which would lower the PGA rate. This type of operational behavior is permissible under the current tariffs for AmerenCILCO and AmerenIP, which AIU contends is the fundamental reason for the proposed changes.

With regard to capacity constraints, AIU indicates that most of the interstate pipelines that it operates on are now constrained in that all or most available firm capacity is under contract with shippers and the utilization of that firm capacity has increased, especially during the summer period for gas-fired power generation. Since 1999, AIU reports that approximately 200,000 MW of gas-fired generation has been built in the U.S. which has a potential demand of 17 Bcf/day compared to the production of natural gas in the lower 48 states of 51 Bcf/day. AIU asserts that this new demand has created significant stress on interstate pipeline operations and has given greater exposure of the natural gas markets to the price volatility of the power markets. Mr. Glaeser also testifies that even in the last 18-24 months there has been a substantial increase in pipelines issuing operational flow orders ("OFO") and system protection warnings.

AIU asserts that one of the contributing factors to the current system integrity issues is the increased reliance on natural gas used for electricity production. Ameren Exhibit 30.1 graphically demonstrates the significant amount of natural gas being consumed by power generation. AIU states that gas-fired generation has the potential of creating near instantaneous peak day demands on the pipeline systems during the summer season, which directly competes for gas supply and capacity for storage injections. AIU contends that this is causing interstate pipelines to operate with tighter tolerances, which are reflected in their tariffs for services such as daily balancing, imbalance cashouts, and penalties, in addition to operational constraints such as interruptible transportation curtailments and pipelines not allowing secondary-out-of-path nominations. AIU states that the demand for natural gas by the power generation sector has become a major source of demand for the gas industry and has created significant competition for natural gas during the summer when gas supply and pipeline capacity for storage injections are critical. In other words, the gas industry has been transformed from a winter peaking industry to a winter and summer peaking industry which has contributed to increased price volatility and constrained pipeline capacity. AIU reports that its own experience with gas generation supports this contention.

Ameren Ex. 30.3 is a graph of AmerenUE's gas generation demand since 2004 which has shown sharply increasing gas demand each year, which even outstripped the utility's internal budget forecasts. In 2004, AmerenUE's gas generation demand was 758,000 MMBtu which by 2007 had risen to 10,494,000 MMBtu or by 1,400%.

AIU submits its transportation tariffs have not changed or adapted to the new operating environment. To eliminate or at least reduce the possibility of marketers exploiting existing balancing services, AIU's proposed transportation tariffs have been designed to maintain tighter system operations in order to protect system integrity and mitigate the impact of gas price volatility on the sales customers. Of AIU's 817,000 total customers, all but 518 are system sales customers. The 518 transportation customers, however, represent a significant level of system throughput. In addition, this is the first real opportunity for AIU to update transportation services to meet the challenges of today's natural gas markets and to develop common transportation services since the acquisition of CILCO in 2003 and IP in late 2004.

To manage such tight interstate pipeline tolerances, AIU contracts for and maintains a portfolio of resources on the interstate pipelines. These resources include services offered by the interstate pipelines such as no-notice storage service, park and loan service, line pack service and park/unpark service, point operator agreements, and operational balancing agreements. These services effectively provide AIU with additional balancing flexibility and banking ability to operate within very tight tolerances. AIU points out that sales customers pay for these services.

Staff witness Sackett disputes AIU's position that interstate pipelines are operating with tighter tolerances since 1999 (when a significant amount of gas-fired generation was built in the U.S.); he further states that AIU has not provided any evidence of tightening pipeline tolerances. In response, AIU states that its actual position is that the operations of interstate pipelines have tightened and become more constrained, not necessarily that their stated tariff tolerance percentages have been reduced over time. AIU relates that many of the interstate pipelines that it utilizes to transport gas are operating at higher capacity levels on a year-round basis, not only due to gas-fired generation demand but also due to regional gas price differentials. AIU reports that mid-continent supplied interstate pipelines like Panhandle and Natural Gas Pipeline Company of America's Amarillo mainline system are sold out of firm capacity since they are connected to some of the least expensive gas production basins in the U.S.

AIU also relays that interstate pipelines are invoking operational restraints more frequently. According to Ameren Exhibit 30.4, there has been an increase in the frequency of interstate pipeline notices calling for specific actions to be taken by shippers on the pipeline systems due to operating constraints. This exhibit reflects a summary of interstate pipeline notifications/alerts during 2007 and January 2008 for critical and non-critical days, force majeure events, line segments being at capacity with Interruptible Transportation/Authorized Over-Run restricted, secondary out-of-path firm at scheduling risk, and line segments being out of service for maintenance.

These notifications/alerts have affected AIU's gas flows on interstate pipelines. Ameren Exhibit 30.5 contains a list of each date during 2007 that a supplier's gas failed to be delivered to the AIU city gate and the reasons why the deliveries were not made. One of the biggest supply interruption events during 2007 was the Panhandle mainline #400 rupture that occurred on November 21. As a result of the rupture, AIU reports that it experienced pro rata force majeure cuts to virtually all of the firm gas supplies being delivered by Panhandle. These cuts in gas supply ranged between 15%-20% of nominated volumes on Panhandle beginning on November 27, 2007 and lasting through January 8, 2008. During this time, AIU states that it was able to maintain the integrity of the system by utilizing its leased no-notice storage and on-system storage resources.

AIU reports that the Panhandle mainline rupture did not cause widespread cuts to the gas supply of transportation customers. In response to Data Request Ameren-CNE-2.06, AIU relates that CNE-Gas states that "between 11/26/07 and 1/8/08, CNE-Gas nominations to an Ameren LDC city gate supplied from Panhandle Eastern Pipe Line were cut due to a supplier force majeure." CNE-Gas notes, however, that "[d]uring this period, CNE-Gas made no special requests to customers to reduce usage" and that "[d]uring this period, there was no specific impact" to its customers. Similarly, in its response to Ameren's Data Request Question No. 1.04, AIU states that IIEC indicates that three of its member companies received service from Panhandle and only one had gas supplies cut off or scheduled off by the pipeline and none of the three had their supply deliveries affected at their facilities. AIU contends that these transportation customers were able to maintain normal usage levels despite the Panhandle rupture because AIU back-stopped the shortage in gas supplies for the transportation customers, similar to the six examples previously discussed (and detailed in Ameren Ex. 30.6), by utilizing system supply resources which, again, are paid for by system sales customers.

AIU states that neither Staff nor CNE-Gas has a sufficient response to its evidence of additional operational restrictions, notifications, and alerts on the interstate pipelines. AIU contends that Mr. Sackett gives no consideration to the factual evidence provided in this proceeding. Subsequently, in response to Staff data request POL 13.11, AIU provided four years of historical data for three of its largest interstate pipelines, which clearly demonstrate an increasing trend of pipeline critical notices numbering over a thousand. While Mr. Sackett acknowledges AIU's response to POL 13.11, AIU states that he then devotes only two sentences to this evidence by saying "Ameren responded to Staff DR Pol-13.11, in which it presented additional summary information that does show that some operational notices increased from 2004 through 2007. However, [Ameren witness Glaeser] offers in his DR that no more than half of these affected Ameren customers." (Staff Ex. 23.0 at 16) AIU observes that Staff fails to mention that all of these notices were critical in nature and exceeded 1,000 in number. AIU contends that this is yet another example of how Staff ignores factual evidence provided by AIU and provides absolutely no evidence of its own. Similarly, CNE-Gas states that AIU has provided "no valid evidence as to whether upstream interstate pipelines are issuing OFOs and other restrictions with increasing frequency"

when questioning whether the new balancing tolerances and transportation service changes are required to protect system integrity and operations. (CNE-Gas Ex. 2.0 at 14) As with Staff, AIU asserts that CNE-Gas simply disregards the evidence provided, while at the same time providing no evidence of its own.

Staff's view that AIU has provided very limited anecdotal evidence of any gaming behavior and no quantification of any harm to sales customers is also mistaken, according to AIU. In its responses to the IIEC Data Requests 2.34, 2.35, and 2.36, which were also provided to Staff, AIU states that it provided detailed examples and in-depth discussion of six individual operating days of transportation imbalances on the system. The information encompassed three examples of transporters net shorting the system and three examples of transporters net longing the system. In each of these examples, AIU states that factual information was provided that would enable a reasonable reader to quantify the cost impact of the imbalance on the system sales customers. AIU calculates that the cost of the three long days totals $51,361 and the cost of the three short days totals $47,822, for a total impact of $99,183 for the six days. AIU contends that Staff chose to ignore the physical evidence by ignoring the value of system gas which was used to manage these imbalances. Even without doing the math, AIU states that the examples clearly show that system resources were used to handle the transporter's imbalance swing and that these system resources were being paid by AIU sales customers. AIU states further that none of the parties in this case dispute the fact that transportation imbalances (longs and shorts) occur at some level every single day on each of the systems. AIU argues that accepting Staff's recommendation means it's a certainty that system resources will be used more and more by transporters at the expense of residential and small commercial sales customers.

With regard to gaming behavior, AIU provided Staff in response to Data Request POL 6.05(g) with concrete examples of two marketers that repeatedly game the systems time and time again for economic gain, including one marketer that games between utilities from weekday to weekends. AIU maintains that some marketers are basically shifting their scheduled gas deliveries on the weekends between customer accounts that are balanced daily and those that are balanced monthly, to avoid having to decrease their gas supplies flowing to the system when the customers' usage decreases substantially on Saturday and Sunday. The marketers move the gas to the monthly balanced customers rather than decreasing the deliveries because gas supplies are typically purchased on a ratable basis over Saturday-Sunday-Monday periods. If the marketer bought the gas only for one of the three days, it would have to pay a premium for the gas or acquire balancing services on the interstate pipeline. AIU observes that one marketer is doing this on the AmerenIP system by shifting gas between Rate 76 daily balanced customer accounts and Rider OT monthly balanced customer accounts. The other marketer, AIU states, actually does this shifting maneuver from daily balanced AmerenCIPS customer accounts to AmerenCILCO monthly balanced accounts.

In response to Mr. Sackett's suggestion that by eliminating the difference between the daily price and the cashout price, any arbitrage opportunity is eliminated, AIU understands the bottom line summary of Staff's arbitrage example to be that the utility's sales customers foot the bill for the arbitrage gain achieved by the transportation customers who may be intentionally either over-delivering or under-delivering gas to the LDC system. AIU agrees that arbitrage opportunities are minimized by Mr. Sackett's suggestion of having daily cashout pricing based upon daily market prices.

ii. AIU's Banking and Balancing Proposal

AmerenCIPS and AmerenCILCO currently offer banking services in the amount of 10 times the average daily peak month ("ADPM")[11] and AmerenIP offers 12 times maximum daily contract quantity, but only for the 87 customers served under AmerenIP Rider OT. All other AmerenIP transportation customers served under Rate 76 currently have no bank service. In its original filing, AIU proposed to eliminate the banking services currently in place for AmerenCILCO and AmerenCIPS as well as the limited banking services available to AmerenIP customers under Rider OT (by eliminating Rider OT as discussed below). Upon further consideration, however, AIU now proposes banking services for all three Illinois gas utilities in the amount of 8 times the ADPM in the prior rolling 12-month period. AIU proposes to revise the banking services for two purposes: (1) bring consistency to the terms and conditions of service among all three companies through Rider T, and (2) to facilitate the continued provision of efficient service in light of emerging economic and industry challenges and trends.

The first reason for revision is self-explanatory: it is plainly beneficial for AIU and its customer to have uniform terms and conditions for transportation service common among all three utilities. As for the second reason for revision, concerning emerging economic and industry challenges and trends, AIU relates that in order to provide service to both transportation and sales customers efficiently, it is important that it anticipate operation needs across its system. Operations of transporting customers typically do not allow them to predict with exact certainty when and how much their future maximum gas demand will be. AIU states that a "bank" is a reserve that transportation customers can tap into to avoid the undesirable financial effects of failing to keep their gas usage within defined tolerance limits. As AIU witness Glaeser explains, banks essentially allow the transportation customer to borrow gas from AIU on days that such a customer may under-schedule and end-up short on gas delivered by suppliers. Banks are used in conjunction with tolerance limits in this manner to give flexibility to transportation customers.

The reforms of its balancing tolerances is another aspect of AIU's overall effort to bring continuity to transportation service across all three companies and to update the terms and conditions of said services as modern economic and industry trends necessitate. AmerenCIPS and AmerenIP currently offer +/- 20% daily balancing with daily cashouts as well as monthly cashouts for any imbalances at the end of the month,

[11] ADPM is the average daily peak from the peak month in the past 12 months.

while AmerenCILCO has only monthly cashouts. AIU views the daily balancing tolerance provision as an important tariff provision because it helps to ensure that AIU can continue to meet the needs of both transportation and sales customers under terms and prices that are reasonable to both. Daily balancing is similar to monthly balancing, the difference being that the time unit upon which a cashout is based is a day rather than a month. AIU states that the actual percentage of daily tolerance allowed by AIU is important because the greater flexibility in balancing tolerances, the greater the isolation that transportation customers have from the economic effects of mismatching the gas they have scheduled for transportation and their actual usage.

AIU proposes to eliminate monthly balancing and cashouts and utilize daily balancing and cashouts alone for each gas utility. AIU believes that daily cashouts will negate the incentive for transportation customers to under- or over-deliver gas supply compared to customer demand. AIU proposes to change the daily imbalance tolerance range to +/- 15% of nomination for each gas utility (it had originally proposed +/- 10%). AIU states that this would effectively provide an operating window of 30% for transportation customers and an intra-month banking level of 4.5 days ((MDQ x 15% daily tolerance x 30 days)/MDQ), where MDQ represents maximum daily quantity. AIU also contends that this will more closely align with the tolerance ranges of the LDC's upstream interstate pipelines. While CNE-Gas is correct that upstream pipeline companies do not have daily cashout, AIU asserts that they do operate with daily tolerance limits ranging from 5% - 10%, and exceeding those limits can result in penalties and other charges.

Specifically, AIU explains that the cash-out proposal is such that whenever the bank limit is maximized, any excess volumes delivered each day are cashed out at 90% of the daily Chicago City Gate price. Imbalance volumes outside of the 15% tolerance band are cashed out with over-deliveries cashed out at 90% of the daily Chicago City Gate price and under-deliveries cashed out at 110% of the daily Chicago City Gate price. Mr. Glaeser adds that in the event an OFO is declared, the daily balance tolerance and bank limits operate in the same manner, with the exception that under-deliveries between 15% and 50% of the daily confirmed nomination ("DCN") are cashed out at 150% of the Chicago City Gate price, and under-deliveries in excess of 50% are cashed out at 200% of the Chicago City Gate price. Over-deliveries in excess of 15% continue to be cashed out at 90% of the Chicago City Gate price. He testifies that the purpose behind these provisions is to ensure an asymmetrical cash-out structure during OFO periods, in order to discourage under-deliveries during periods of constrained system operations. In the event of a Critical Day or curtailment, Mr. Glaeser states that the daily balance tolerances are reduced to zero and all imbalance volumes that deviate from the DCN are cashed out. All over-deliveries are cashed out at 90% of the Chicago City Gate price, while under-deliveries from 0% to 50% are cashed out at 150% of the Chicago City Gate price, and under-deliveries in excess of 50% are cashed out at 200% of the Chicago City Gate price. Again, he states that the purpose for this particular structure was to strongly discourage under-deliveries during Critical Days to preserve system integrity.

AIU notes that Mr. Sackett supports a bank limit of 10 times the maximum daily contract quantity ('MDCQ"), while CNE-Gas favors banking service with a limit 14-16 times the MDCQ. CNE-Gas' proposal, however, depends on the availability and flexibility of other features of Rider T. Specifically, CNE-Gas proposes to increase the banking limits to 10-12 times a transportation customers' MDQ if the daily tolerance stays at 20%. If the daily tolerance band is lowered to 15%, CNE-Gas proposes to increase the banking limits to 11.5-13.5 times a transportation customers' MDQ. If Staff's proposal for daily cashout and banking is adopted, CNE-Gas supports a banking limit of 14-16 times a transportation customers' MDCQ.

AIU notes that these proposals dramatically increase the allowable bank limits over the levels that are currently in effect for AIU. All of the bank limit proposals advanced by CNE-Gas and Staff are based on a specific number, e.g. 10, 12, 14, or 16 times a transportation customers' MDQ or MDCQ. These terms refer to the maximum daily contract quantities defined in a transportation customer's contract and are in many cases substantially higher than a customers' actual usage.

Despite the arguments of Staff and interveners, AIU proposes to allow customers a bank limit equal to 8 times the ADPM in the prior rolling 12-month period. This bank limit will allow the customer to under- or over-schedule gas and avoid cashout when operating outside of the proposed tolerance limit of +/- 15% until the limit is either exceeded or the balance is depleted. Additionally, AIU is agreeable to allowing transportation customers that are served by the same interstate pipeline to transfer bank limit balances provided confirmation of the exchange is established. This important addition to banking services will assist in giving greater flexibility to transportation customers and mitigate the loss of flexibility associated with the necessary lower banking limits. AIU is also willing to modify the cashout mechanism to eliminate the utilization of the PGA rate and to base cashouts, both positive and negative, on the Platt's Gas Daily "Midpoint for Chicago Citygates," which represents a market based price.

b. Staff's Position

i. Comparison of Proposals

Staff identifies five differences between Mr. Sackett's banking proposal and AIU's proposal: (1) the size of the banks, (2) the balancing tolerance, (3) the application of cashout premiums, (4) the resulting injection and withdrawal limits, and (5) access to banks on critical days. With regard to the size of the banks, Mr. Sackett proposes that the bank size be 10 times MDCQ while AIU proposes 8 times ADPM. MDCQ reflects a larger measure of the demand put on the system than ADPM and will be used by AIU in its demand charges. IIEC recommends 10 times ADPM and CNE-Gas proposes 14-16 times MDCQ, if a straight daily cashout is approved. Mr. Sackett observes that the Commission ordered Nicor to use a 28 times MDCQ limit for its banking service in Docket No. 04-0779, so he believes that including the MDCQ metric is consistent with other Commission Orders. He explains his basis for the 10 times MDCQ level as being

a compromise between the 12 times MDCQ currently available to AmerenIP Rider OT customers and the 10 times ADPM currently available for Rider T banks at AmerenCILCO and AmerenCIPS.

With respect to the balancing tolerance, Mr. Sackett maintains that the 20% band currently in place does not need to be reduced to the 15% that AIU has proposed. He argues that AIU's evidence was purely anecdotal and its calculations of detriment were grossly over-stated. Under his proposal, with the straight daily cashout, the spread between market price and the cashout value is eliminated, which he believes will remove any incentive for transporters to game the system to exploit favorable economic conditions.

Mr. Sackett asserts further that AIU characterizes its proposal to reduce its daily balancing tolerance as a necessary consequence of decreasing tolerances on the pipelines from which it receives service. He notes, however, that a historical review of the tariffs for the interstate pipelines that AIU pointed to in support of an alleged trend toward the tightening of tolerances revealed that the current tariff sheets are nearly identical to tariff sheets in place in 1995-1997. Mr. Sackett avers that there have been no significant tariff revisions with regard to imbalance penalties and cashouts in the last five years that would require any changes in AIU's tariffs. In fact, he adds, some overrun charges have even declined on NGPL since 1995.

Staff states that AIU did not respond directly to Mr. Sackett's criticisms regarding the pipeline tolerances; instead, it sidestepped that issue and attempted to make it appear that what it really meant was that there were increasing operational issues. AIU supported the operational issues argument by alleging a trend of increased OFOs caused by operating constraints. Staff responds that the increase in OFOs demonstrated by AIU do not justify decreasing the daily balancing tolerances as proposed by AIU. Mr. Sackett asserts that no other major Illinois gas utilities – Nicor, Peoples, and North Shore – have eliminated storage services for transportation customers.

Concerning cashouts, Mr. Sackett's proposal would apply the cashout mechanism to the post-bank imbalance. Thus, under his proposal, withdrawals from the bank will not be treated as the use of system gas nor will injections into the bank be treated as "dumping" gas on the system. Mr. Sackett contends that AIU's proposal, which applies the cashout bandwidth to the initial imbalance before any use of the customers' bank, does treat withdrawals from the bank as the use of system gas and injections into the bank as "dumping" gas on the system. In addition, he notes that AIU would treat all gas left on the system in excess of the bank limit differently than the imbalances at the other end of the bank. Under AIU's proposal, Mr. Sackett understands that excess gas is automatically cashed out at 90% regardless of the percentage of the initial imbalance. If the bank balance is insufficient to cover the initial imbalance, it would be cashed out at 110% of the market only if it was in excess of the 15% band. Under his proposal, all normal imbalances are treated symmetrically.

Mr. Sackett explains further that the tolerance band should not be applied to the customer's initial imbalance, but rather the net customer usage of system resources after the injection or withdrawal is complete. Customer usage of system gas in excess of 20% of what is available from that customer's bank should be cashed out at 110% of the market price for that day. He believes that his approach removes the incentive to arbitrage price since transportation customers would have no incentive to over- or under-deliver. Mr. Sackett asserts that the addition of gas to the bank and the withdrawal of the gas from the bank do not constitute using system gas, but gas that already belongs to the transportation customer. Injecting gas is not "dumping" gas; it is using the resources approved by the tariff, according to Mr. Sackett.

Mr. Sackett testifies further that a 20% withdrawal and 20% injection limit should be in place. He asserts that this permits transportation customers to use their banks for balancing and limited physical hedging. He adds that this gives transportation customers more of the benefits that sales customers receive from storage. In general, Mr. Sackett believes that a customer should be allowed discretion in using its bank; some of the benefits from the bank are from balancing and some from storage.

If the Commission determines that standardizing the tariffs to provide for a daily cashout is appropriate, Staff argues that it should approve tariff provisions that modify the AmerenCIPS tariff design to eliminate the proposal for monthly balancing. Staff states that the current AmerenCIPS tariff has daily balancing along with a bank and offers the option of a stand-by reserve ("SBR"). This design allows for the most options for transportation customers while closing up some of the "flaws" AIU alleges are in the existing tariff.

Staff also reports that when AIU proposed its bank limit service, it included no access to the bank on a Critical Day despite the fact that all of its current banks allow for limited access. Mr. Sackett believes that the tariff should allow limited access to the bank on a Critical Day with wording similar to AmerenCIPS' existing method, if the Commission approves the retention or expansion of the SBR (total use of system gas and bank withdrawal equal to the designated SBR amount). If the Commission does not approve the retention or expansion of the SBR, Mr. Sackett believes that the Commission should order AIU to adopt AmerenCILCO's method for allowing access to banks (50% of MDCQ).

ii. Access to Storage Assets

A central difference in the case has been Mr. Sackett's objection to the reduced access to storage assets. AIU maintains that those resources are solely required to meet the needs of its sales customers. Mr. Sackett disagrees with this for six reasons.

First, Mr. Sackett objects to AIU not providing equal access to storage resources for transportation customers by linking use of its monopoly storage resources to the purchase of a commodity. He explains that because system customers receive the benefit of the on-system storage through lower costs, if AIU eliminates or reduces the

bank for transportation customers, when a customer switches from sales to transportation service, the switch results in the customer being denied the use of utility storage assets.

Second, Mr. Sackett notes that the Commission has consistently taken the position that system assets are for the benefit of all customers. When a customer shifts from system supply to transportation service, Mr. Sackett contends that access to system assets should be retained. He asserts that transportation customers, through their fees, compensate the utility for the appropriate use of utility resources that exist to serve all customers. Mr. Sackett rejects the premise that these assets should be used to meet the needs of sales customers first and foremost.

Third, CNE-Gas argues that while "Ameren claims it does not have the resources necessary to provide storage service to transportation customers, [t]he real question of equity is not whether there is enough storage available, but how to fairly allocate the storage that is available . . . . It is inappropriate to simply conclude that because a utility has fewer total volumetric amounts of storage resources than another utility that it should not have to equitably allocate the resources it does have." (CNE-Gas Ex. 1.0 at 16-17) Both CNE-Gas and Staff point out that the ratio of owned storage assets to throughput shows that AIU has sufficient assets to share them with both customer groups. AIU objects to only looking at owned storage but Mr. Sackett notes that AIU itself made a distinction between the two when it claimed that it needed all of its owned storage assets to meet peak day demand for its sales customers and most transportation customers pay for the use of on-system storage.

Fourth, AIU also makes the argument that transportation customers can purchase these same basic services on the interstate pipelines. Mr. Sackett contends, however, that the services offered by the interstate pipelines are not a reasonable substitute for the services provided by the LDC. He argues that these services are not close substitutes to LDC services for several reasons, including the restrictive nature of AIU's tariffs. Mr. Sackett states that interstate pipeline balancing service addresses only the problem of an imbalance with the pipeline; it would not address imbalances with the LDC. Differences between deliveries from the pipeline to the LDC and the customer's usage must be addressed by a balancing service provided by the LDC itself, according to Staff.

Fifth, AIU argues that it requires all of its owned storage resources to meet peak day demand for its sales customers and that the Commission has approved this allocation in PGA proceedings. Staff asserts that Commission findings of prudence in a PGA proceeding do not demonstrate an understanding and acknowledgement that the resource allocation of AIU's peak design day excludes transportation customers. The PGA proceedings deal with cost recovery and do not include a thorough review of the allocation of storage assets between sales and transportation assets. Mr. Sackett adds that it is not clear from the demand studies that AIU has provided whether or not AIU includes transportation customers in its peak design day. AIU's witness testifies that he believed that banks' withdrawals and imbalances were a part of the "historical look"

provided by this demand study. AIU's witness also agrees that customers have a right to withdraw gas from their banks on a Critical Day until undergoing curtailment. However, since curtailment does not affect all transportation customers or transportation customers exclusively, Staff contends that AIU must be meeting some of this demand even during a curtailment. Staff asserts that Mr. Glaeser's artificial (and confusing) distinctions about exactly where this gas comes from should carry no weight with the Commission because there is no difference between the gas that flows from the storage fields and that which is flowing from line pack or other system resources.

Sixth, AIU claims it is not providing "storage" for transportation customers, although it admits it is providing banking services for transportation customers under both AmerenCILCO's and AmerenCIPS' current Rider T and AmerenIP's Rider OT. Staff states that this is a distinction without a difference. Staff explains that banking is a service whereby a transportation customer delivers more gas than it consumes. This gas, under specified circumstances, is taken by the utility and the transportation customer has specified rights to have that amount of gas returned to the transporter when its usage exceeds its deliveries from the pipeline to the utility system. Staff contends that storage fields provide flexibility to address differences between deliveries into the utility system and usage by its customers (sales and transportation). While the companies may account for transportation customers' banks as a general obligation to provide a similar amount of gas back to them, storage fields certainly facilitate this practice. Indeed, to support a reduction in transportation customers' access to storage services, Staff relates that AIU misleadingly argues that it lacks the excess storage capacity that other utilities have. According to Staff, AIU offers no proof that it can not provide Staff's recommended storage services.

iii. Gaming

Staff observes that AIU has also listed potential gaming as a major factor for many of its tariff changes. Mr. Sackett points out three reasons why AIU's argument has no merit: (1) reliance on anecdotal evidence, (2) flawed calculations of detriment to sales customers, and finally, (3) the presence of other, more focused options to address gaming if it did exist. First, Staff asserts that the anecdotal examples AIU provided fail to demonstrate gaming. Similarly, Mr. Sackett testifies that AIU failed to consider net effects of imbalances in the opposite direction. Before tariff revisions should be made to address gaming, Staff states that AIU must demonstrate that gaming exists. Staff contends that AIU has proposed dramatic changes to address a problem that it has failed to demonstrate exists.

Second, Mr. Sackett pointed out flaws in AIU's analysis of the detriment and cost to other customers. When calculating the negative impact on sales customers, he observes that AIU neglected to account for its cashout rules. Mr. Sackett contends that this omission causes a gross overestimate of the cost that the imbalances impose on sales customers. Staff submits the cashout rules protect sales customers, and as a result of the cashout rules, Mr. Sackett indicates that these imbalances might end up benefitting sales customers.

Specifically, in its analysis of over-deliveries, Staff maintains that AIU miscalculates the detriment to sales customer by using the avoided cost of the transportation customers. Staff contends that AIU fails to acknowledge that transportation customers have suffered a loss in the value of the gas that they bought at the First of the Month price regardless of whether they sell the gas at a loss that day or store the gas on AIU's system. Staff asserts that AIU incorrectly suggests that the customers avoid this loss by putting gas onto AIU's system and uses this spread multiplied by the net positive imbalance to calculate the cost to sales customers. Staff argues that it is unreasonable to calculate the dollar amount of cost to the system sales customers and to include the value of the supposed benefit to transportation customers as a cost to sales customers.

In analyzing under-deliveries to the system, Mr. Sackett testifies that AIU fails to account for the different methods by which the negative imbalances are cashed out. Some negative imbalances are cashed out at the market price plus 10%, some get ‘repaid’ by positive imbalances during the remainder of the month, and the rest get cashed out at the end of the month. Mr. Sackett argues that AIU's calculation, which multiplies each imbalance by the full spread between the daily price and the end of month price, overstates the size of the detriment to sales customers because it ignores those other cashouts.

Third, Mr. Sackett asserts that his recommended tariff modifications are more focused and thus would better resolve the problem. He suggests that AIU's daily imbalances could be cashed out at the daily spot price. He believes that this proposal addresses the possibility of an arbitrage occurring because of a difference between the cashout price (the average of the daily prices for the month) and the market price for a particular day. Mr. Sackett states that the incentive for arbitrage could arise if the daily price were high relative to the expected average monthly price; a customer might have an incentive to arbitrage the two prices by under-delivering gas on that day. Alternatively, if the daily price is low compared to the expected average monthly price, a customer might have an incentive to arbitrage the two prices by over-delivering gas on that day. Mr. Sackett contends that his recommendation would eliminate the difference between the daily price and the cashout price, thus eliminating the arbitrage opportunity. He adds that premiums on the cashout price for imbalances greater than 20% bands would be employed to encourage accurate nominations. Customers using system gas in excess of that 20% would be cashed out at 110% of the market price for that day. Over-deliveries would roll into a bank to the extent there it is not full up to 20 percent of the excess delivery; any additional gas would be cashed out at 90% of the daily price. Finally, the order of deliveries would follow the Commission-approved tariff in AmerenCIPS’ Rider T.

Staff opposes the "extra" penalties for over-deliveries during OFOs and Critical Days. Staff recommends that over-deliveries on such days be cashed out exactly the same as other deliveries. Staff contends that over-deliveries by transportation

customers will help the utility meet its supply shortcomings for sales customers on such occasions.

c. IIEC's Position

IIEC is opposed to the elimination of the current banking provisions for AmerenCILCO and AmerenCIPS and recommends the 10-day of MDQ banking allowance be applied to all three of the AIU utilities. The fact that AIU is agreeable to providing storage equal to 8 days of ADPM demonstrates, in IIEC's opinion, that AIU does not need all of its storage to serve its sales customers. IIEC contends that AIU should provide storage banks equal to 10 days of MDQ to all of its transportation customers as a matter of equity and to facilitate the broader use of its system.

IIEC notes that AIU proposed to restrict customers' ability to use even the 8-day bank. Under AIU's latest proposal, IIEC understands that customers would be required to cashout any imbalances in excess of AIU's proposed 15% tolerance limits even if the customer had sufficient gas in its bank to cover the full imbalance. Specifically, under AIU's proposal, if a customer under-delivers to the system, but has sufficient bank balances to cover that under-delivery, the customer will only be allowed to withdraw an amount of gas from his bank that is less than or equal to the 15% daily tolerance amount. If the customer has a shortfall in deliveries of 17%, the extra 2% must be cashed out. IIEC argues that AIU has not shown that imbalances cured by the use of the customer's own banked gas will have any adverse impact on the amount of costs AIU incurs to serve its sales customers. IIEC maintains that transportation customers should be allowed to cure any imbalances by adding to or withdrawing from gas in their banks whether within the tolerance limits or not. In other words, if the customer's gas supply is unavailable on a particular day, but the customer has sufficient gas in its storage bank to cover its usage, it should be able to use that banked gas to meet its needs without having to cash out usage in excess of the daily 15% tolerance.

With regard to the specific tolerance limit proposed by AIU (15%), IIEC maintains that AIU has not shown any need to tighten the tolerances currently in place for AmerenCIPS and AmerenIP. IIEC recommends maintaining the present 20% tolerance limit and the application thereof to all three companies. IIEC contends that the only evidence of any problems provided by AIU relate to its examples using six "hand picked" days when there were large imbalances on the system. In its calculations, which purport to calculate the harm to sales customers as a result of transportation customers' actions on these days, IIEC states that AIU apparently did not reflect offsetting imbalance charge payments from transportation customers in its analysis. Thus, IIEC concludes, AIU's analysis is incomplete and fails to consider that sales customers may have benefitted from the events described.

In addition, IIEC reports that AIU has incurred only minimal imbalance penalties under the current 20% tolerances for AmerenCIPS and AmerenIP, thus it is not clear what problem AIU is addressing in reducing the tolerances from 20% to 15%. IIEC contends that AIU has not provided sufficient evidence of harm to sales customers as a

result of the actions of transportation customers under its existing tariffs, so as to justify a reduction in the daily imbalance tolerances. IIEC states further that AIU (1) has not provided specific studies or investigations, (2) has not provided sufficient proof or evidence that the gaming behavior alleged in its testimony has actually occurred, and (3) has not demonstrated that the behavior of transportation customers has systematically or consistently raised costs to sales customers. Absent a clear demonstration that there is a problem with the current 20% tolerances, IIEC asserts that they should be maintained, and applied to all the companies, but only as long as a bank equal to 10 times the customer's MDQ is made available.

d. CNE-Gas' Position

CNE-Gas understands AIU to be proposing a bank limit for each gas utility based upon 8 times the ADPM. CNE-Gas also understands that the ADPM is the same methodology that is currently employed by AmerenCILCO and AmerenCIPS in determining bank size except that the number of days used is currently 10 versus the 8 proposed. CNE-Gas observes that not only is 8 days less than the current 10-day banking service, but also the use of ADPM results in less bank capacity than if based upon an MDQ or MDCQ as is used by AmerenIP and other Illinois gas utilities. CNE-Gas states that there is no quantifiable data to support 8 days per se; it is simply offered as a compromise. While some banking is better than none, CNE-Gas continues to have concerns with: (1) the size of the bank, (2) the ability to inject and withdraw gas from that bank, (3) the parameters for bank limit transfers, or imbalance trades, and (4) the 15% daily tolerance limit.

i. Access to Storage

CNE-Gas asserts that it and AIU have markedly different views regarding AIU's storage assets. CNE-Gas understands AIU's position to be that company-owned storage assets are exclusively for the benefit of sales customers and that its resources are insufficient to provide equivalent storage service to transportation customers. According to CNE-Gas, AIU posits that transportation customers should at best benefit from its storage assets only to the extent storage is needed to provide a minimum level of balancing. AIU seeks in these proceedings to reduce the balancing flexibility afforded to transportation customers. CNE-Gas, however, contends that AIU has offered no studies or formal analysis to warrant this reduction.

When AIU's storage fields were developed, virtually all of its customers were bundled sales customers. Today, CNE-Gas notes that AIU's customers have a choice of gas supplier, and the Commission has taken steps in the recent Nicor and Peoples rate case orders to ensure that customers electing to purchase gas on an unbundled basis from suppliers other than the LDC are able to obtain transportation services that include equivalent use of the utility's resources, including storage. CNE-Gas reports that the Commission previously determined that Nicor's current allocation process for firm storage that is based upon MDCQ is fair to all customers. CNE-Gas relates that Nicor determines allocations by dividing the total amount of storage by the peak day

sendout, with the result constituting the firm storage or SBR entitlement, authorized at 28 times MDCQ, for each customer including sales customers, customer select customers, and transportation customers. CNE-Gas argues that AIU can not reserve storage for sales customers alone, as AIU's storage assets are utility customer assets rather than sales or transportation customer assets. CNE-Gas states that a full share of AIU's storage assets must be made available to each firm customer class under equivalent terms and conditions of service.

CNE-Gas states further that other Illinois gas utilities provide storage not only for balancing purposes, but also storage that allows transportation customers to purchase less expensive summer gas for consumption during the winter when prices are generally higher. CNE-Gas contends that AIU faces the same environment of price volatility and constrained energy infrastructure that other Illinois gas utilities face, yet other utilities have not found it necessary to reduce transportation customer storage banks to the minimal levels proposed by AIU. Moreover, CNE-Gas continues, AIU's proposed denial of comparable storage is not only unduly discriminatory, but also would result in an unfair competitive advantage for bundled utility sales service over third party suppliers. CNE-Gas asserts that AIU's undue discrimination is illustrated by the outcome that if an AIU transportation customer elects to return to sales service, that customer would again have access to AIU storage through bundled sales. The storage assets are available to support all customers. CNE-Gas states that AIU simply elects to deny storage rights to customers that deign to purchase gas from its competitors. Ultimately, CNE-Gas fears that permitting AIU to preserve such a competitive advantage for its bundled sales service will stifle competition and reduce customer alternatives.

ii. Sufficiency of Storage Resources

CNE-Gas suggests, in evaluating AIU's argument -- that there are insufficient resources to provide larger storage banks to transportation customers -- the Commission should not ask whether there is enough storage available but how to allocate fairly the storage that is available. Even though storage resources may be limited, CNE-Gas contends that it is equitable that all utility customers share equally in those assets that do exist. CNE-Gas and Staff offered evidence comparing AIU's storage assets with those of other major Illinois utilities. Although AIU argues it has inadequate storage resources to offer more than 8-day bank limit service, CNE-Gas argues that comparisons with other Illinois utilities dispute such a claim. While differences exist between utility assets that warrant differences in the services offered by each utility, CNE-Gas maintains that the small differences in storage assets do not warrant the substantial differences between service offerings that AIU proposes compared to Peoples, North Shore, and Nicor.

On page 16 of its Initial Brief, CNE-Gas provides a table summarizing the storage assets of six Illinois gas utilities, including the three AIU LDCs. Based on total storage as a percentage of annual customer use, CNE-Gas observes that AIU has somewhat less storage available than either Peoples or Nicor. This slightly lower capacity,

however, does not justify transportation storage banks that are less than one-third of the capacity of the storage banks offered by the other utilities, according to CNE-Gas.

CNE-Gas reports that in 2006 AmerenIP, the largest of the three AIU gas utilities had annual transportation throughput of 33.5%. CNE-Gas states that in contrast, Nicor in its last rate case reported transportation gas throughput of 47.1%, and, Peoples in its recent rate case reported a volume of just over 40%. CNE-Gas contends that AIU's successful transition to unbundled competitive alternatives will not match the success of Nicor or Peoples if the Commission permits it to skew the benefits of storage access towards its bundled sales customers.

CNE-Gas urges the Commission to authorize transportation storage banks of 12 times MDCQ if daily balancing tolerance remains at 20%. If the daily balancing tolerance is reduced to 15%, CNE-Gas states that a storage bank of 13.5 times MDCQ is more reasonable. In either case, CNE-Gas notes that the AIU storage bank would still remain comparatively lower than those of other Illinois utilities.

CNE-Gas claims further that it is unnecessary to establish extreme safeguards for sales customers that are designed to remedy purely hypothetical ills, especially when they result in the allocation of excessive costs to transportation customers. CNE-Gas does not believe that AIU provided adequate evidence that a reduction in the size of transportation customer storage banks is warranted. In support of its position, CNE-Gas asserts that (1) AIU's anecdotal examples of gaming of the system or subsidization of transportation customers were discredited, (2) AIU did not establish that reduction in the size of storage banks is essential to project system integrity, (3) AIU's storage banks for transportation customers are already relatively smaller than those of other Illinois utilities, (4) storage assets are utility assets that should be equitably allocated between both sales and transportation customers, and (5) imbalances are normal operating conditions for which storage banks are a reasonable and proven means to address.

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 sales and transportation customers in the future.

iii. Injection and Withdrawal Requirements

CNE-Gas states that the function of a storage bank depends not only upon the total volume of the bank, but also the ability to inject gas into the bank and withdraw gas from that bank. Unfortunately, CNE-Gas finds that AIU's proposed bank limit service makes it extremely difficult to inject or withdraw gas from storage on a planned basis when the supplier is concerned that the amount in the bank is too low or high. The design of the service allows storage injections or withdrawals only to extent that the quantity of gas remaining is within 15% of the DCN after any imbalance between actual

usage and deliveries is taken into account. As an example, CNE-Gas states that "if a supplier anticipates a customer will use 850 therms/day, but also wants to inject gas into its storage banks, if the customer has sufficient capacity in its bank, the supplier may make a nomination of 1,000 therms, hoping that 150 therms will be injected into its bank." (CNE-Gas Initial Brief at 18) Since an imbalance invariably occurs if the customer has a 6% imbalance and actually uses 800 therms for the day, with the DCN of 1,000 therms, 150 therms would be injected into the storage bank, and the remainder would be purchased by AIU at a discount of 90% of the market price. To avoid this penalty, CNE-Gas states that the supplier's only recourse is to lower the DNC, thereby reducing the risk of selling gas to AIU at the discount, but also lowering the quantity of gas injected into storage. Id.

If the 6% imbalance occurred in the opposite direction, and the customer instead uses 900 therms rather than the 850 anticipated, with the DCN of 1,000 therms, only 100 therms are now available for injection. Since usage projections are not precise, and any unanticipated imbalances must first be accounted for, CNE-Gas contends that storage injections are haphazard at best under AIU's proposal. Over weekends and holidays, when the ability to forecast usage is even more challenging, CNE-Gas fears that actual imbalances may deviate more than even the 15% daily balancing tolerance, resulting in a storage withdrawal when an injection was planned or vice versa.

In the above examples, the customer either made a storage injection of 9% of the DCN or, when making a storage injection of 15%, also was forced to sell any excess gas at a discount. At best, the customer could make an injection of up to 15% of DCN without a penalty. The latter scenario, CNE-Gas states, assumes perfect knowledge of customer usage, which is unrealistic and would seldom, if ever, occur.

In comparison, CNE-Gas points out that Nicor permits storage injections of 200% of the MDCQ compared to AIU's proposed 15% of DCN (by definition MDCQ/MDQ is larger than DCN). Even in Peoples' recent rate case, in which additional storage injection limits were implemented, CNE-Gas reports that injections of 100% MDQ during the winter months are allowed, with somewhat tighter limits during April through October. Yet, even the more restrictive injection season limits, CNE-Gas asserts, are significantly more liberal than those of AIU. CNE-Gas states that during the injection season Peoples permits injections that equate to average daily use in the parallel month of the prior year plus 0.67% of the customers' bank.

CNE-Gas urges the Commission to reject AIU's overly restrictive injection and withdrawal limits. CNE-Gas notes that the Commission has previously stated that "[t]o the extent possible, the Commission would prefer to increase rather than reduce the flexibility of customers, whether Transportation customers or [other] customers." (Docket No. 04-0779, Order at 131) Because AIU's proposal is based on DCN, CNE-Gas asserts that it is more limited than Peoples' or Nicor's bank system. CNE-Gas adds that AIU would further limit transportation customer flexibility by permitting storage injections and withdrawals of only 15% of the DCN before a discounted cashout sale to AIU or premium cashout purchase by AIU.

CNE-Gas recommends that the Commission require AIU to adopt injection and withdrawal limits of one times MDQ. CNE-Gas acknowledges that even this limit is more restrictive than those of Nicor and Peoples. In the alternative, if the Commission determines limits of one times MDQ are not reasonable in this case, when storage banks have sufficient capacity, CNE-Gas believes that AIU should permit storage injections up to 100% of the DCN and, once the bank is full, excess gas would be purchased by the utility at 90% of the market index price. Since, according to AIU, its storage bank capacity is limited to no more than a handful of days, CNE-Gas states that customers would be prevented from making large, ongoing injections as their storage bank capacity would max out rather quickly. Thus, customer deliveries to storage are limited to less than 15% or 20% (depending upon the daily tolerance level approved) on most days. Storage withdrawals, CNE-Gas adds, would be limited to actual daily usage; however, once the storage account has a zero balance, any purchase of gas from AIU for balancing purposes would be made at 110% of the market index price.

iv. Imbalance Tolerance

While CNE-Gas prefers AIU's current 15% daily tolerance proposal over its original 10% proposal, CNE-Gas asserts that there are several reasons that it is more appropriate for AIU to use a 20% daily cashout imbalance parameter. First, CNE-Gas states that a daily cashout already introduces a significantly new concept for AmerenCILCO customers, which currently only use a monthly cashout. Second, because AIU proposes to continue to use a monthly cashout in conjunction with a daily cashout, CNE-Gas contends that even at a 20% daily tolerance, AIU continues to capture monthly imbalance deviations through its graduated tier of premiums and discounts.

Third, CNE-Gas questions AIU's argument that it needs to reduce its daily tolerance to 15% in order to align more closely with the tolerance ranges of the LDC's upstream interstate pipelines. CNE-Gas points out that none of the pipeline tariffs under which AIU currently secures firm service has any daily cashout provision whatsoever. Under existing pipeline agreements, CNE-Gas states, AIU does not currently adhere to daily cashout of imbalances that are greater than 20%, let alone the lower tolerance level proposed. Thus, CNE-Gas concludes, there is nothing that makes AIU's proposed 15% daily cashout tolerance inherently comparable with the existing pipeline tariffs to which AIU is subject.

Fourth, CNE-Gas asserts that AIU offers no credible evidence that the current 20% daily cashout tolerance level is not adequate. AIU instead identifies existing pipeline tariff restrictions of 5% or 10% as justification for the reduction in its daily tolerance; however, CNE-Gas demonstrates that these restrictions are not directly comparable to a daily cashout tolerance as suggested by AIU. Thus, CNE-Gas argues that there is no record evidence that the current daily cashout tolerances do not offer sufficient incentive to keep transportation imbalances at reasonable levels. The situation is exacerbated, CNE-Gas continues, by AIU's proposal to retain a monthly

cashout with tighter month-end tolerance levels. In response to AIU's claims of transportation customer gaming, CNE-Gas responds that AIU's anecdotal evidence does not establish that any gaming behavior has occurred.

CNE-Gas maintains that keeping imbalances within 20% on a daily basis, and less than 10% at a monthly level, before penalties are applied, is reasonable. CNE-Gas states that AIU offers no evidence that shows that the existing 20% daily cashout tolerance must be reduced to 15% in order to (1) more closely align with upstream pipelines, (2) provide additional incentive to transportation customers to reduce imbalances than what already exist, (3) address more frequent OFOs, or (4) prevent transportation customer gaming. CNE-Gas believes that the addition of a 20% daily cashout tolerance to AmerenCILCO tariffs, in addition to the retention of a 20% daily cashout in AmerenIP and AmerenCIPS tariffs, adequately resolves certain of the problems identified by AIU. CNE-Gas asserts that it is unnecessary to also add further restrictions by lowering the percentage.

CNE-Gas is also uncertain whether AIU intends to require both daily and monthly cashouts for transportation customers. CNE-Gas supports the use of a monthly cashout in addition to a daily cashout. CNE-Gas observes that under Staff's proposed 10-day storage bank, a daily cashout alone offers less storage capacity than a dual daily and monthly cashout mechanism. CNE-Gas explains that this is due to the loss of monthly cashout and the flexibility it provides to transportation customers which allows them to accumulate volumes during the course of a month. This functionality is described by AIU witness Glaeser as the intra-month bank. To remain on par with current service levels (which Staff argues should occur under an across-the-board rate increase), CNE-Gas states that under the daily cashout proposal, the size of the storage banks must be greater than the proposed 10 times the MDCQ if service levels are to remain roughly equal. While it prefers the current monthly and daily cashout mechanism in conjunction with a storage bank, CNE-Gas adds that daily cashout alone would be an acceptable alternative if less restrictive injection and withdrawal limits are implemented and the size of the storage bank is increased to account for the elimination of monthly cashout balances.

AIU further describes what happens with daily cashout and bank limits during an OFO and Critical Day. CNE-Gas states that in both instances AIU proposes extreme measures, but since these measures first appeared in surrebuttal testimony and no detailed tariff sheets were offered in support, CNE-Gas laments that interveners had little opportunity to respond. CNE-Gas contends that AIU has provided no evidence to justify why zero Critical Day tolerance is acceptable, nor why it is reasonable to discount excess gas supply under such conditions while doubling the cashout price of purchases. On a Critical Day, CNE-Gas asserts that a primary concern is having sufficient supplies delivered on AIU's system, yet if a marketer over delivers gas, AIU wants to penalize the over deliveries as well by cashing them out at 90% of market. To avoid the substantial penalties associated with under deliveries on Critical Days, CNE-Gas states that a prudent marketer may attempt to over deliver to some degree in order to avoid the under delivery penalties, yet AIU proposes to also penalize marketers for over delivery,

even though on a Critical Day adequate gas supply is critical for system integrity. CNE-Gas argues that penalties for over delivery during an OFO or Critical Day simply fail any logic.

CNE-Gas reports further that AIU proposes to also implement a $6.00/therm charge for unauthorized gas usage during Critical Days. CNE-Gas states that this is in addition to the premiums just discussed that are applied to cashout. CNE-Gas does not object to implementation of the unauthorized gas charge penalty per se, but does object to the cumulative unfavorable treatment of transportation customers during OFOs and on Critical Days.

e. Commission Conclusion

As noted above, AmerenCILCO and AmerenCIPS transportation customers may currently avail themselves of a 10-day ADPM bank, and AmerenIP Rider OT customers may avail themselves of a 12-day MDCQ bank. AIU proposes to apply an 8-day ADPM bank to all transportation customers of all three utilities. Staff proposes a bank size based on 10 days of MDCQ, while IIEC proposes a bank size based on 10 days of MDQ. CNE-Gas proposes varying bank sizes depending on other factors such as imbalance tolerances.

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.[12] 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. The ADPM unit, however, has not been applied as broadly in Illinois. Moreover, under AIU's proposal of a rolling 12-month period, the ADPM would seem to change from month to month, which the Commission believes may unnecessarily hamper and/or complicate banking.

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

[12] Peoples and North Shore's tariffs indicate that they calculate bank size using MDQ, which is more similar to MDCQ than ADPM.

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. The Commission also wishes to clarify that banks do not represent gas "borrowed" from a utility, as AIU suggests. Gas in a figurative bank represents gas owned by a transportation customer.

As for access to bank gas, if the Commission does not approve the retention or expansion of the SBR service, Staff witness Sackett believes that the Commission should order AIU to adopt AmerenCILCO's method for allowing access to banks. AmerenCILCO's current Rider T addresses access to banks and provides in part that a transportation customer on Rate 550 or 600 may access up to 50% of its MDQ while a customer on Rate 650 or 700 may access up to 50% of its MDCQ on a Critical Day. The Commission finds AmerenCILCO's current access terms acceptable with the modification that a transportation customer otherwise eligible for service under GDS-2 or GDS-3 may access up to 50% of its MDCQ on a Critical Day and one times MDCQ on normal days. For all other transportation customers, the limits for both Critical Days and normal days shall be 20% of DCN.

The appropriate daily balancing tolerance is the next issue to be resolved. AmerenCIPS and AmerenIP currently offer +/- 20% daily balancing. AIU has proposed a 15% tolerance, while Staff, IIEC, and CNE-Gas propose 20%. As noted above, the Commission recognizes AIU's resource concerns, but is not convinced that adoption of AIU's position is warranted. In consideration of the 10-day MDCQ bank size, the Commission believes that it is reasonable to adopt a 20% tolerance band. After gaining some experience with this tolerance band in conjunction with the other conclusions regarding transportation service, the Commission may revisit this issue and further revise the tolerance band (either up or down) in AIU's next gas rate cases.

With respect to cashouts following imbalances outside of the tolerance band, AmerenCIPS and AmerenIP currently employ daily cashouts as well as monthly cashouts for any imbalances at the end of the month, while AmerenCILCO has only monthly cashouts. CNE-Gas appears to want to retain both daily and monthly cashouts. AIU, Staff, and IIEC, on the other hand, recommend only daily cashouts for transportation customers. In light of concerns over whether daily telemetry is warranted for smaller transportation customers, as discussed below, the Commission is not inclined to approve daily cashouts for transportation customers that would otherwise be GDS-2 or GDS-3 sales customers. Monthly cashouts only shall be used for such smaller transportation customers. For the remaining transportation customers, daily cashouts are reasonable and approved.

The cashout mechanism should only be applied to the post-bank imbalance. In other words, when calculating an imbalance, withdrawals from the bank will not be treated as the use of system gas nor will injections into the bank be treated as “dumping” gas on the system. Additionally, over-deliveries on Critical Days shall also be cashed out the same as over-deliveries on any other day. Over-deliveries by

transportation customers will help the utility meet its supply shortcomings for sales customers on Critical Days. The Commission also notes that AIU is agreeable to allowing transportation customers that are served by the same interstate pipeline to transfer bank limit balances provided confirmation of the exchange is established. The Commission finds AIU's proposal reasonable and adopts it. AIU's proposal to implement a $6.00/therm charge for unauthorized gas usage during Critical Days is also hereby approved. If a transportation customer's gas usage is not measured by the LDC on a daily basis, for purposes of applying any penalties connected to unauthorized use on a Critical Day, the transportation customer's daily usage should be determined by prorating the total usage during the billing period over the number of days in the billing period.

2. AmerenIP Rate 76 as a Stand-Alone Tariff

a. AIU's Position

AIU witness Warwick proposes to eliminate the existing Rate 76--Transportation of Customer-Owned Gas from AmerenIP's rate schedules as part of its effort to create a new, consistent Rider T that will implement uniform terms and conditions for transportation service across all three gas distribution company service territories. The conversion would be accomplished by increasing each of the Rate 76 components by the overall base rate percentage increase and then re-segmenting the components into the non-residential GDS rates to conform to the uniform structure common to the AmerenCILCO and AmerenCIPS tariffs. AIU believes that eliminating Rate 76 in favor of Rider T will result in a tariff layout that is easier to understand and more logically consistent, which is particularly important for those entities that have multiple facilities and/or customers in the various AIU service territories.

AIU's proposal to remove AmerenIP's Rate 76 as a stand alone tariff does not affect the proposed base service rates (i.e., Customer Charge, Demand Charge, Overrun Demand Charge) of the customers affected by this change due to the across-the-board increase proposal of AIU. AIU contends that the resulting rate values are the same whether Rate 76 is a stand alone tariff or as stated under the proposed Rider T. AIU also notes that, under its proposal, changes to Rider T's service terms and conditions are applicable to current AmerenIP Rate 76 customers under either the stand alone or merged basis.

Staff witness Sackett criticizes generally the effort to consolidate transportation rate structures into Rider T and therefore opposes the elimination of the individual company transportation riders. Staff witness Harden objects to eliminating Rate 76 out of concern that doing so may result in unequal bill impacts on customers. AIU asserts that Staff supports consistency, but only if it does not create any cost impacts for transportation customers. With the across-the-board increase to each delivery service rate component, AIU states that it is not clear or apparent what, if any, unequal bill impacts may result. AIU asserts that there is no apparent record evidence to justify Staff's position.

b. Staff's Position

Because she fears that the elimination of Rate 76 could result in unequal bill impacts, Ms. Harden opposes this change and proposes that an across-the-board increase should be applied to each rate for each customer class without making any tariff eliminations that may cause unequal bill impacts. Staff also does not believe it will be clear to customers that the resulting rate values will be the same whether Rate 76 is on a stand-alone or merged basis. In addition, Staff does not agree with AIU's contention that "in conforming tariff structures that differ across three service territories, certain provisions enjoyed by certain customers will be eliminated." (AIU Initial Brief at 330) Staff contends that AIU's choice to eliminate services and offer fewer choices to transportation customers is a deliberate one, not forced by any changing energy market requirements.

c. Commission Conclusion

The Commission does not share Staff's concerns about eliminating AmerenIP's Rate 76 as a stand alone tariff in light of the manner in which AIU proposes to do so. Specifically, it is unclear how unequal bill impacts to AmerenIP transportation customers will occur. The Commission also recognizes that AIU is not proposing to incorporate Rate 76 into Rider T as a result of changing energy markets, but rather is doing so based on its own preference. Such a motivation, however, does not alone warrant rejecting AIU's proposal. In any event, the Commission finds that its other conclusions regarding rate design will sufficiently protect transportation customers. Those who believe that additional provisions regarding transportation customers are warranted are free to raise them in AIU's next gas rate case. Intervening transportation customers and marketers have not objected to AIU's proposal.

3. Elimination of AmerenIP's Rider OT

a. AIU 's Position

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. AIU states that such an option invites economic gaming by participating customers in a manner that burdens the operation of an efficient system. In response to criticism from Staff witness Sackett and GFA witness Adkisson related to rate impacts from eliminating Rider OT, AIU has proposed to grandfather existing Rider OT customers within existing GDS rate classifications. The grandfathering proposal applies to the monthly rate values only; all other terms and conditions will be pursuant to the proposed Rider T provisions. AIU explains that the benefit of grandfathering is the ability to satisfy existing customers on the rate while not allowing additional customers to be added to the rate. The limitation grants existing Rider OT customers AIU's recommended across-the-board percentage change and, at the same time, provides a

transition mechanism consistent with Mr. Glaeser's testimony to eliminate Rider OT. AIU states that the retained Rider OT rate structures will be located within each non-residential GDS classification, GDS-2 through GDS-6. If a grandfathered customer on Rider OT elects Rider S, AmerenIP will purchase any remaining banked gas at the average market price for the year. If a grandfathered customer chooses Rider T, AIU states that the customer will have to deliver an appropriate amount of gas on a daily basis to the AmerenIP system to cover its usage.

In response to Staff's claim that Rider OT should not be eliminated because it provides a valuable service, allows for monthly balancing, contains no daily metering requirement, and provides system back-up service, AIU notes that only 87 customers are taking this service. While Staff acknowledges this is a small percentage of the total customer base, it claims that this may be an indictment of the current service offerings. AIU contends that this argument makes no sense since AmerenIP's current service offerings provide for bank services and extreme tolerance levels--both of which Staff claims are sorely needed by transportation customers. AIU also observes that Staff's proposed bank services and tolerance levels are not much different than what is currently being offered. To accept Staff's position on Rider OT, AIU continues, it follows that Staff's own proposal falls short.

b. Staff's Position

Staff witness Sackett recommends that the Commission reject AIU's proposal to eliminate AmerenIP's Rider OT. He contends that Rider OT should be retained because it provides a valuable service to transportation customers by giving customers an option between a service designed for large customers (Rider T) and one that allows for monthly balancing, no daily metering requirement, and system back up, all of which are ideal for smaller customers (Rider OT). In the previous gas rate case, Docket No. 04-0476, he notes that the Commission accepted AmerenIP's proposal to eliminate the banks for Rate 76 in part based upon AmerenIP's argument that those services were available under Rider OT. He believes that that policy goal of maintaining a banking storage service option for transportation customers is as important now as it was when the Commission entered its Order in Docket No. 04-0476. Indeed, Mr. Sackett continues, it may be more important now; without Rider OT, all customers, regardless of size, are forced onto the proposed Rider T.

Contrary to AIU's assertion, Mr. Sackett argues further that the services under Rider OT are valuable to transportation customers. He maintains that the fact that 87 AmerenIP customers currently pay for the services demonstrates that Rider OT is valuable. While 87 customers represents a small percentage of the total customer base for which the service is available, Mr. Sackett contends that this may be more of an indictment of AIU's current service offerings than an indication that a particular service has no value. He fears that AIU's current transportation service will become even less attractive if AIU's proposed reductions in services are approved. Mr. Sackett recommends that the Commission focus on the level of service that transportation customers receive and how much it costs. If the Commission adopts his proposals, he

asserts that AIU's transportation service will become a better value, and it is likely that more customers will switch to transportation service.

Staff also notes that AIU's primary objection to Rider OT is that it “allows customers essentially to switch back and forth between system sales gas and transportation service . . . ." (Ameren Ex. 16.0 at 40) Staff notes further that AIU opines that such an option invites economic gaming by participating customers in a manner that burdens the operation of an efficient system. Staff states that AIU made both an economic argument about gaming and this operational argument, but failed to prove either of them.

With regard to AIU's "grandfather proposal" for Rider OT, Mr. Sackett does not consider it to be an adequate response to his concerns. He notes that under the grandfather proposal the services would still change to Rider T services, eliminating many of the advantages of Rider OT to customers and, thus, be detrimental to Rider OT customers. Mr. Sackett recommends retaining Rider OT services entirely and increasing its rates across-the-board. In light of the value of Rider OT to AmerenIP customers, he goes on to argue that if the Commission approves tariff standardization at this time, a similar service provision that appeals to smaller customers should be offered in all three service territories.

c. GFA's Position

GFA opposes eliminating AmerenIP's Rider OT. GFA contends that AIU's proposal is just one example of its willingness to make tariff structure changes to favor its own natural gas supply. Despite AIU’s claims to grandfather Rider OT, GFA states that AIU's plan only retains monthly rate values increased by the proposed across-the-board percentage increase. All other terms and conditions, GFA notes, will be pursuant to Rider T provisions. GFA asserts that AIU's Initial Brief is misleading where it states that the benefit of grandfathering is the ability to satisfy existing customers on the rate while not allowing additional customers to be added to the rate. According to GFA, the benefits of Rider OT are actually stripped by AIU's proposal to make all Rider OT terms and conditions to be pursuant to Rider T. GFA states that AIU recognizes that tariff conformity across three service territories will eliminate certain provisions enjoyed by certain customers, but AIU again is only willing to conform tariffs when it is favorable to its own natural gas supply.

d. Commission Conclusion

AmerenIP's Rider OT does appear to have some benefits for smaller transportation customers, as Staff argues. In light of the Commission's earlier conclusion on storage banks and subsequent conclusions on daily telemetry and a small volume transportation tariff, however, the Commission does not believe that Rider OT remains a necessary vehicle for delivering those benefits to small transportation customers. Storage banks will also continue to exist for larger transportation customers and thus will not be needed under Rider OT. Grandfathering Rider OT for AmerenIP

customers currently taking service under it appears to be of little benefit as proposed by AIU and thus is not adopted. Elimination of AmerenIP's Rider OT in conjunction with the other rate design conclusions in this Order promotes uniformity in the tariffs of the three gas utilities without unduly sacrificing service to transportation customers. Accordingly, AIU's proposal to eliminate AmerenIP's Rider OT is approved.

4. Elimination of AmerenCIPS' Stand-by Reserve

a. AIU's Position

Of the three AIU gas utilities, only AmerenCIPS currently offers SBR service. AmerenCIPS provides SBR through its existing Rider T. SBR is a service that provides for full or partial system back-up during periods of curtailment. Customers desiring SBR service elect what portion of their gas load that they would like available during periods of curtailment. AIU proposes to eliminate AmerenCIPS' SBR service, claiming that few customers want this service and eliminating it will achieve consistency among the three gas utilities.

AIU acknowledges Staff's claim that 50% of eligible AmerenCIPS customers (74 customers) have or want SBR service and that it should continue to be offered. In response, AIU assets that Staff's analysis is in error. AIU states that Mr. Sackett combined the number of Rider T and Rider S customers to determine the number of customers wanting SBR service. AIU notes, however, that he only used the number of Rider T customers to derive the percentage currently utilizing a designation amount greater than zero. Of those eligible for a partial designation, AIU contends that 0.4% actually utilize a designation greater than zero, rather than 20% erroneously claimed by Staff. Ameren Exhibit 30.7 shows the SBR option statistics for customers with Rider T, Rider S, and a combination of Rider T and S.

AIU note further that prior to its 2002 rate case, Docket No. 02-0837, AmerenCILCO offered a SBR option called daily limited firm backup ("DLFB"). AIU reports that in that rate case, the service was eliminated due to limited participation by transportation customers. Additionally, AIU states that the elimination of DLFB was uncontested by all parties, including Staff.

Furthermore, AIU contends that there are not enough pipeline capacity resources in the Midwest to offer SBR service, which has its origins in the 1980's, when transportation services were new and untested. AIU explains that SBR was originally designed during the initial unbundling of transportation services to give a back-stop to the new and untested transportation services then being offered. Because it targets a reserve margin (available firm deliverability resources over a design peak day) of 3% for load growth between capacity agreement terms, statistical errors in modeling the peak design day, and minor customer switching, AIU asserts that it simply does not have any extra firm resources on a peak day to offer a SBR option. As evidence of the lack of capacity, AIU relates that the newest interstate pipeline under construction in the U.S., the Rockies Express Pipeline, is fully subscribed before going into service.

If it is forced to offer a SBR service for all transportation customers, AIU states that an additional 490,000 MMBtu of firm transportation capacity potentially would be required, at a cost of over $74 million. AIU does not believe that it could secure this much firm capacity even if it wanted to, which makes Staff's request for this service a moot point. AIU adds that when a customer chooses to take transportation service, it is accepting the responsibility to secure its own gas supply and upstream transportation capacity resources, especially for a peak day. AIU insists that it should not be obligated to contract for supply services to serve as a back stop for transportation customers.

b. Staff's Position

Staff argues that AIU's proposal to eliminate AmerenCIPS' SBR service is another example of AIU's efforts to "standardize" the service offerings among the AIU LDCs, but which reduce services for transportation customers. Mr. Sackett recommends against allowing the elimination of this service. According to Staff, SBR service recognizes the need for operational flexibility and is a valuable service to transportation customers which should be retained as a cost-based service option. Staff adds that SBR service will become even more valuable if curtailments become more common due to the increasing pipeline constraints that AIU predicts. In that eventuality, Staff states that SBR would serve as a functional mechanism to ensure gas supply to customers when needed. Moreover, rather than eliminating the AmerenCIPS SBR option, Mr. Sackett recommends standardizing AIU's tariffs by offering SBR in all three service territories.

Mr. Sackett contends that AIU has provided no compelling reason to eliminate SBR. In attempting to justify eliminating the AmerenCIPS SBR option, Staff states that AIU makes two mutually exclusive arguments. First, Staff notes that AIU questions the popularity of SBR service among eligible customers. Then, Staff continues, AIU argues that it would not be feasible to provide SBR service if all customers that would be eligible took full backup under it.

Staff asserts that AIU's argument about SBR's lack of popularity is off the mark because its calculation includes the total number of commercial and industrial sales and transportation customers served by AmerenCIPS. Staff calculates that 74 AmerenCIPS sales and transportation customers are paying for a partial designation of greater than 0%. Staff contends that it is evident from their willingness to pay for SBR that they find it beneficial. Staff adds that there is no indication that the costs of SBR are not being recovered from the customers electing this service. Furthermore, Staff argues that the popularity of SBR can be most appropriately determined by considering the percent of Rider T customers taking SBR. These are transportation customers and therefore are the customers that Staff proposes should have access to the service from all three utilities. Staff asserts that according to AIU's own numbers, 20% of AmerenCIPS' transportation customers are designating a SBR amount greater than zero. Staff notes that transportation customers tend to fall in higher usage classes and may be subject to curtailment before the sales customers that are primarily in the lower usage classes.

Mr. Sackett concludes that it is inconsistent for AIU to on the one hand argue that the vast majority of AmerenCIPS' Rider T customers have elected a stand-by level of zero and on the other hand state that AIU could not find capacity to provide this service if all customers wanted this service at a full back-up level.

c. Commission Conclusion

The decision of whether to eliminate AmerenCIPS' SBR service is not easy. Clearly some customers find it useful enough to pay extra for it, as Staff asserts. At the same time, however, the Commission recognizes that pipeline capacity resources in the Midwest have become more constrained since the initiation of SBR service, as AIU argues. Upon weighing all of the arguments, the Commission is persuaded by AIU. As noted above, AmerenIP has no SBR option and AmerenCILCO's equivalent to the SBR service was eliminated in its 2002 rate case without dispute. In light of this historically declining interest in SBR service, the Commission does not believe that retaining AmerenCIPS' SBR service is warranted, let alone expanding it to all three gas utilities. Although it is unlikely that all customers taking SBR service would designate all of their load for the service, the Commission is also concerned about AIU's ability to secure capacity throughout its systems. Accordingly, AIU's proposal to eliminate AmerenCIPS' SBR service is approved.

5. Intra-Day Nominations

Generally, a nomination in the context of the gas industry is a request for a quantity of gas under a specific contract or agreement with a gas supplier. An intra-day nomination is a request for gas received during the same day on which the customer wants to take delivery of the gas. An intra-day nomination may also be a request for gas received after the normal nomination deadline for the following day. One or more intra-day nominations, while not mandated for all LDCs, are the industry standard.

The NAESB, and its predecessor the Gas Industry Standards Board, have developed various standards for the purpose of ensuring smooth and efficient operations between producers, pipelines, local distribution utilities, marketers, and others. NAESB is the industry forum for the development and promotion of standards which will lead to a seamless marketplace, and its process for development and implementation of standards is consensus-driven. Among the promulgations of NAESB is a recommendation that LDCs implement one or more of 4 intra-day nominations, specifically the Timely Cycle (before 11:30 AM on the day before flow), Evening Cycle (before 6:00 PM on the day before flow), Intraday 1 Cycle (before 10:00 AM on the day of flow), and Intraday 2 Cycle (before 5:00 PM on the day of flow). Intra-day nomination cycles provide transportation customers the ability to change nominations when necessary after the earlier deadlines have passed. The need to adjust nominations can arise for numerous unexpected reasons, including weather conditions, changes in a customer’s production schedules, or pipeline or utility system disruptions. Many LDCs have either voluntarily or by mandate implemented certain of the NAESB intraday standards.

a. AIU's Position

AIU currently utilizes the Timely nomination cycle. AIU proposes the addition of one new intra-day nomination cycle for all three gas utilities to give transportation customers an additional option to adjust gas supply deliveries to minimize imbalances. AIU proposes to add a new intra-day nomination cycle at 4:00 PM on the preceding day and use its best efforts to accommodate other intra-day nomination changes. AIU is only willing to provide this additional nomination on normal business days.

In response to the suggestion that it provide all 4 NAESB nomination cycles, AIU urges the Commission to refrain from ordering it to do so. AIU argues that doing so is not necessary because other Illinois gas utilities do not offer all 4 NAESB nomination cycles, which suggests to AIU that there is no need for the additional cycles, that it presents an undue cost to ratepayers, and that there has been no credible demand for this service. AIU states that it will provide the 4:00 PM evening nomination and any other off-cycle nominations it is able to using its current staff and resources.

AIU reports that the majority of transportation customers and their marketers efficiently manage their nominations and have not requested intraday nomination deadlines. AIU states that it has worked with the transporters to support their occasional need to make late nomination changes. AIU adds that there is no credible proof that additional intra-day nominations will meaningfully assist utilities in managing imbalances on interstate pipelines. Furthermore, AIU will continue to provide nomination flexibility when possible, but indicates that it can not uphold a firm tariff obligation to provide intra-day nominations throughout all evening and weekends and holidays without providing additional staffing during the off business hours.

The need for added personnel, AIU continues, is not limited to handling the additional intra-day nominations. AIU relates that it must coordinate nomination changes with Gas Supply and Gas Control personnel in order to effectuate the changes. Offering intra-day nominations would require additional staffing during the off business hours for these groups as well. AIU operates a 24-hour Gas Control Center; however, it is staffed during off-business hours strictly for meeting the requirements of gas control and monitoring for the transmission system, on-system storage fields, distribution level operating pressures, and maintaining the integrity and safety of the systems.

With regard to CNE-Gas' contention that other utilities offer all 4 intra-day nomination cycles, AIU notes that CNE-Gas excuses Peoples, North Shore, and Nicor for not being among them because these utilities allegedly offer more flexible storage access. AIU responds that its proposed banking services and tolerance levels are comparable to what these other utilities have in place. Furthermore, AIU asserts that its storage assets are considerably more limited than what Peoples, North Shore, and Nicor have in place, as discussed by AIU witness Glaeser. According to Mr. Glaeser, Peoples and North Shore have considerably more “leased” storage than does AIU. Furthermore, AIU avers that Peoples and Nicor do not offer firm intra-day nomination

cycle rights. AIU states that Nicor has a strict nomination deadline of 11:30 AM the day prior to flow, with no flexibility for late nomination changes. In the recent Peoples/North Shore rate order, AIU reports that the Commission rejected the same arguments made by CNE-Gas. Moreover, AIU indicates that the utilities which CNE-Gas utilizes for comparisons, such as Pacific Gas and Electric Company and Southern California Gas Company, offer little resemblance to AIU in terms of the size of the their distribution systems, customer base, and employee numbers and, in fact, are the largest gas distribution systems in the U.S.

b. Staff's Position

Staff recommends that AIU be required to implement all 4 NAESB intra-day nominations. Doing so, Staff argues, will assist each LDC in maintaining its balances on the interstate pipelines. Staff states further that the additional costs to provide this service could be passed through to transportation customers in rates in subsequent rate cases. Staff points out that AIU can change its pipeline nominations twice during the gas day, but is not willing to pass this flexibility on to its transportation customers.

In support of AIU’s position that there is no demonstrated need for these additional nomination cycles, Staff notes that AIU argues that most of its transportation customers have not requested intraday nominations and most of them manage their nominations efficiently. Since AIU did not consult with its transportation customers about its proposed offerings, however, Staff believes that AIU's first argument has no validity. If AIU had sought input from its customers prior to filing its service revision, Staff submits that it may have discovered that they do want this service. Additionally, the fact that AIU spent three rounds of testimony arguing that its transportation customers do not efficiently manage their nominations as a basis for its recommended changes weakens AIU's second argument on this issue, according to Staff.

Staff also notes AIU's dislike of CNE-Gas' comparison of AIU to other LDCs that offer these nominations as firm rights. Although AIU dismisses two of the other utilities on the grounds that they are significantly larger, Staff observes that this leaves seven other utilities for comparison, many from the Midwest. Staff also believes that AIU's comparison to Nicor, Peoples, and North Shore on this issue is not valid because all of these utilities offer enough flexibility that intra-day nominations would be less critical for them.

c. CNE-Gas' Position

CNE-Gas states that transportation customers, like utilities, may benefit from the use of intraday nominations to avoid imbalances or for other operational reasons. To aid in doing so, CNE-Gas provides suggested tariff language incorporating all 4 NAESB intra-day nominations. CNE-Gas asserts that such intra-day nominations would be similar to what AIU's own internal gas supply personnel do, by using this capability to help maintain supply stability. CNE-Gas suggests that AIU should discontinue its unduly discriminatory treatment of transportation customers and instead provide them

the same options for the same reasons AIU desires intraday nominations – to help manage its load requirements when unanticipated changes occur.

In response to AIU's observation that neither Nicor nor Peoples offers the 4 firm intra-day nomination cycles, CNE-Gas acknowledges that this is true and counters that both Nicor and Peoples provide transportation customers with greater, more flexible storage access. As CNE-Gas witnesses explained, many of these issues are interrelated. CNE-Gas contends that AIU's approach seeks to provide transportation customers with little flexibility on all the interrelated items, including both intra-day nominations and storage banks. In comparison, CNE-Gas states that Nicor offers no flexibility on intraday nominations, but substantially greater flexibility on the storage banks provided to transportation customers. In the recent Peoples case, CNE-Gas relates that the Commission authorized several tariff provisions granting greater flexibility to transportation customers such as intraday allocations, greater flexibility during delivery restrictions, expanded imbalance trading, and April through October daily storage injection rights of up to the average daily use in the parallel month of the previous year plus 0.67% of the customers Allowable Bank, with the ability to inject up to a customer's MDQ during the remaining months. With the added flexibility for transportation customers, CNE-Gas states that the Commission elected not to require Peoples to offer the greater flexibility of intraday nominations.

d. Commission Conclusion

The Commission appreciates the benefits that more intra-day nomination cycles could bring to AIU's gas distribution systems and the customers thereof. In light of uncertainties regarding the cost of implementing all 4 cycles, however, the Commission is not prepared to require AIU to provide all 4 at this time. To order AIU to provide new services in this rate case but defer cost recovery until AIU's next rate case is not appropriate. 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. In the meantime, the Commission approves of AIU's proposed 4:00 PM evening nomination cycle, in conjunction with its current Timely nomination cycle. The Commission also expects AIU to use its best efforts to try to accommodate any other off-cycle nominations it is able to using its current staff and resources, as it committed to doing.

6. Daily Telemetry

a. AIU's Position

AIU proposes to require customers taking service under GDS-4, GDS-5, GDS-6 (AmerenCILCO only) and Rider T to provide daily telemetry. AIU witness Glaeser explains that daily telemetry is needed so that AIU can be assured of timely

communication of transportation customer usage. He states further that daily telemetry allows AIU to provide transportation customers and marketers with more current data since the meter can be interrogated on a daily basis after 9:00 AM, which is the end of the gas day in the natural gas industry. AIU indicates that transportation customers and marketers would now have access to usage data from the previous day rather than usage from two days prior to the current gas day. Mr. Glaeser testifies that the daily telemetry requirements can be met with a dedicated telephone line, which can be an extension of an existing line. The line, however, could not be used for fax or any other purpose.

In response to GFA witness Adkisson's argument that the expense is not needed for small to intermediate and off-season transportation customers, Mr. Glaeser testifies that notwithstanding each customer's individual size, in the aggregate their usage can have a meaningful impact on the operations of the distribution systems. He adds that this concern of undue impacts can be exacerbated with regard to the smaller captive distribution systems within AIU's overall distribution systems. AIU offers the Crawford County area, as well as the Franklin, Hamilton and Perry County areas as examples of captive distribution systems. AIU states that daily information on transporters' usage can serve to prevent negative system impacts for these particular areas. Mr. Glaeser also notes that the requirement that these sized customers be subject to the daily telemetry requirements is not novel--AmerenIP already requires daily telemetry for transportation customers served under Rate 76.

Mr. Glaeser testifies further that there is a real benefit to transportation customers and their marketers by having this information in that they can better avoid higher cash-out prices. Moreover, he opines that in this day and age when state and federal policies abound with regard to the need for energy efficiency and responsible energy usage, these customers should bear some obligation to take measures by which to ensure responsible energy management. He went on to explain that, as a matter of fact, many transportation customers and marketers are desirous of this daily usage information. He testified that when such information is not posted on the management system in a timely basis, numerous inquiries are received from these customers/marketers. Even marketers who manage customers with relatively small loads that include the GDS-2 and GDS-3 customers are desirous of access to daily usage information in order to manage the aggregated imbalances associated with their customers. AIU does not respond to GFA's suggestion that if daily telemetry is required, that its installation be delayed until after November 2008.

With regard to GFA's concern about the additional expense of telemetry, AIU describes how GFA misunderstands AIU's proposal with a discussion of AmerenIP and a GDS-2 grain dryer customer. GFA asserts that a sales customer will see the incremental cost for telemetry increase to $660 annually, whereas, if it is taking delivery service, as would a transportation customer, the overall annual increase is $1,345. AIU explains that for an AmerenIP GDS-2 customer taking service under Rider T, the incremental cost for daily telemetry does increase, by the overall across-the-board increase, to $660 annually, but the $1,345 amount includes the annual daily telemetry

charges ($660), as well as the increase to all other rate components within the rate. Thus, according to AIU, a current grain dryer customer taking service under GDS-2, who would also be taking transportation service under grandfathered Rider OT rate structure, will see the same across-the-board increase in GDS rates as a customer receiving sales service. AIU asserts that the current grain dryer customer taking transportation service under AmerenIP's Rate 76 (proposed Rider T) will realize the same across-the-board increase in GDS rates as customers receiving sales service.

In response to Mr. Sackett's concern that a $55 per month charge for telemetry presents an economic barrier for smaller customers and may force some transportation customers to move back to system supply, AIU asserts that such claims are simply wrong. First, AIU states that nothing is unique or novel about this particular charge. AmerenCIPS currently charges $55 per month for the same equipment, and the AmerenIP Rate 76 Facilities Charge and Advance Metering and Telecommunications Charge total $37.75 per month. Second, AIU asserts that the evidence is that small transportation customers at both AmerenCIPS and AmerenIP are not being deterred by paying these monthly charges. AIU states that there are many customers taking transportation service and are paying these charges. AIU witness Warwick testifies that AmerenCIPS has 125 small transportation customers while AmerenIP has 182 accounts under its Rate 76.

AIU acknowledges 4 objections made by Mr. Sackett in response to Mr. Warwick's testimony: (1) the number of small customers taking transportation service are a small percentage of eligible customers, (2) the conclusions drawn stem from current metering differentials and not the proposed charges, (3) while the metering charge may not be a barrier for some smaller transportation customers, it could still be a factor for others, and, (4) while it may be economical for current customers, it may keep other marginal customers from benefiting from transportation services. AIU contends that it is readily apparent that the majority, if not all, of Staff's objections are speculative and not grounded in any credible evidence. Mr. Warwick testifies that less than 1% of the small transportation customers eligible take such service from AmerenCILCO, which does not require a telemetry charge, suggesting Staff's claim that more customers would be interested fails. Mr. Warwick also emphasizes that the magnitude of the telemetry charges is driven by the across- the- board revenue allocation such that each rate value, including the telemetry charges, are being changed equally by the across-the- board percentage change. Taken to its logical extreme, any increase in any of the AIU rates may cause major behavioral changes on the part of all of its customers but, of course, such a result is not realistic. AIU asserts that there are cost increases and the affected businesses become more efficient, reduce their own costs, or pass them along to their customers. AIU states that it is difficult to conclude that a charge of less than $2 a day would prevent a customer from utilizing transportation service.

b. Staff's Position

To the extent that daily balancing is not necessary, Staff sees no reason for daily telemetry. Staff is also concerned that the expense of daily telemetry may discourage

some customers from becoming transportation customers. Staff also suggests that AIU apparently does not understand that some customers may not have an extra $660 or $660.00 per year for telemetry fees lying around. According to Staff, the additional fee puts marketers at a disadvantage because they not only have to beat the PGA cost, they also have to beat it by this additional amount as well. Staff adds that AIU witness Warwick testifies that other factors would affect a customer's decision to remain on sales service and that the move to daily balancing, the loss of a bank, the requirement for a dedicated phone line, and a reduction in a daily balancing could all be factors.

In response to AIU's claim that because some small customers are taking service with daily balancing and telemetry there must be no barrier for anyone, Staff argues that there may be many other smaller customers that are not taking transportation service because they can not get gas priced competitively enough to beat not only the PGA but also the costs associated with the daily balancing and cashout and the telemetry and metering charges. With regard to AIU's observation that AmerenCILCO does not have daily balancing and metering requirements but only a few transportation customers, Staff submits that it is really AIU's unfavorable policies that keep customers, especially the small ones, from finding transportation service to be desirable. Staff fears that the number of transportation customers is likely to grow smaller if AIU’s restrictive proposals are approved.

c. GFA's Position

GFA understands that daily telemetry is a useful and necessary tool for large users to manage the system’s daily operation, but contends that daily telemetry is not necessary, nor an industry standard, for predictable small to intermediate users. For example, GFA states that telemetry requires the additional cost to obtain and maintain metering equipment. In addition, the user will pay one-time installation costs as well as the monthly cost of a dedicated phone line. On top of those costs, the user will incur additional administrative costs to manage the daily use data. GFA argues that all of these costs are justified for large users who need to manage the daily operation of the system, but are simply too large and disproportionate to the use of small and intermediate users. Indeed, GFA continues, the large cost results in an economic incentive for transportation users to switch to AIU supply. For example, under AIU's proposal, GFA reports that a small AmerenIP GDS-2 grain dryer customer under sales service will see its incremental cost for telemetry grow to $600 or $660.00 annually. If it is taking delivery service, its overall increment, compared to sales service, will increase to $1,345.00.

GFA disagrees with AIU's assertion that daily telemetry information helps transportation customers avoid higher cashout prices. The fallacy of that statement for a small grain dryer is obvious, according to GFA. GFA explains that the additional cost of AIU's filed tariffs has a bias in favor of its sales service supply by $2.24 per dekatherm relative to transportation service, which far exceeds what a small customer could expect to make up by avoiding higher cash-outs. In response to AIU's claim that some GDS-2 and GDS-3 customers or marketers would like to have daily usage

information, GFA states that daily telemetry should be an option for those willing to pay for it.

GFA states that AIU's purported justification is that it would be nice to have daily telemetry to be able to monitor actual usages and manage imbalances in the system. AIU also suggests that it is good "overall energy policy" to require daily telemetry. All of that, GFA asserts, ignores the significant, and hugely disproportionate, cost to the small to intermediate users. Instead of being good overall energy policy, GFA views this proposal as a thinly veiled attempt by AIU to force transportation customers to take AIU supply.

To see the lack of necessity for daily telemetry, one need look no further than other suppliers within Illinois, as well as the rules applicable to Missouri and Iowa utilities, according to GFA. Nicor, Peoples, North Shore, Mid American Energy Company, and AmerenCILCO currently offer small volume transportation service without telemetry. The State of Missouri, GFA states further, prohibits telemetry charges for small volume transportation for Missouri schools, which is applicable to AmerenUE, Laclede Gas Company, Missouri Gas Energy Company, Atmos Energy, Aquila, and any other utility regulated by the Missouri Public Service Commission. (See 393 Mo.Rev.Stat. §393.10) Furthermore, GFA reports that the Iowa Utilities Board recently ordered all Iowa investor-owned utilities to offer small volume transportation service without telemetry to all non-residential customers. These other utilities and state statutes and rules demonstrate that daily telemetry for the small to intermediate users is simply not necessary.

d. Commission Conclusion

The Commission understands AIU to propose that all Rider T transportation customers and all sales customers taking service under GDS-4, GDS-5, and GDS-6 (AmerenCILCO only)[13] to provide daily telemetry. Transportation customers otherwise eligible for service under GDS-2 and GDS-3 would provide daily telemetry under Rider T. Sales customers under GDS-2 and GDS-3 would not be required to provide daily telemetry.

The Commission agrees with AIU that daily telemetry can provide useful information, but does not understand the sales vs. transportation distinction that AIU draws between customers eligible for GDS-2 and GDS-3 service. The record lacks any explanation for why daily telemetry is not necessary for small sales customers but is for small transportation customers. In light of the cost of daily telemetry, the Commission views the proposed requirement on small transportation customers as a deterrent to taking transportation service. Accordingly, AIU may not require all transportation customers otherwise eligible for service under GDS-2 and GDS-3 to provide daily telemetry. Nor may AIU require small seasonal gas transportation customers otherwise eligible for service under GDS-2 or GDS-3 to provide daily telemetry. AIU shall, however, offer a daily telemetry option to such transportation customers in the same

[13] AmerenCIPS and AmerenIP do not have a GDS-6 rate class.

manner that other, larger transportation customers provide daily telemetry or on more favorable tariffed terms to the customer if costs prove to be less for smaller customers. AIU's proposal to require remaining Rider T customers and GDS-4, GDS-5, and GDS-6 customers to provide daily telemetry appears reasonable and is approved.

7. Small Volume Transportation Tariff

a. Staff's Position

Staff witness Sackett recommends implementing a small volume transportation tariff for all three utilities if the Commission determines that tariff standardization is appropriate at this time. He suggests a transportation service that balances monthly and does not require daily metering for smaller customers. He asserts that daily metering and balancing are unnecessary for smaller customers because they do not place the same constraints on the system as large customers. Mr. Sackett states further that no metering charge should be assessed beyond what these smaller customers would need for system supply service. With regard to telemetry, if the customer would not need telemetry as a sales customer, he does not believe that the customer should be required to have telemetry as a transportation customer.

Mr. Sackett notes that AIU already offers daily balancing and no telemetry in AmerenIP's territory under Rider OT and under existing Rider T in AmerenCILCO's territory. Therefore, he suggests that it should not be unduly difficult to add this to AmerenCIPS' tariff, as well. Mr. Sackett contends that AIU did not respond in either its rebuttal or surrebuttal testimony to his proposal to add a small volume transportation tariff for all three utilities. Since no party objected to this recommendation in their testimony, he asserts that the Commission should adopt it (if the Commission adopts tariff standardization).

b. AIU's Position

AIU objects to the implementation of a small volume transportation tariff and opposes monthly cash-outs for any sized customer. In addition, AIU finds Staff's position regarding proposed monthly cash-outs for small volume transportation customers to be at odds with Staff's own take on the benefits of daily cash-out. Specifically, AIU notes that Mr. Sackett agrees that daily cash-outs would help to eliminate gaming as part of his argument that bank services should remain. AIU adds that Mr. Sackett's position is consistent with Staff's position in AmerenIP's last gas rate case, Docket No. 04-0476. According to the Order in Docket No. 04-0476, Staff agreed with AmerenIP that daily balancing would prevent a certain amount of gaming in the monthly balancing and cash out procedures. (Order at 90)

c. GFA's Position

GFA expresses discontent with AIU's transportation tariffs. GFA states that it sponsors a natural gas purchasing and transportation pool for its members. These

members are predominantly small and intermediate size grain dryers. GFA witness Adkisson testifies that its members are seriously considering switching to sales service with AIU supply because the proposed AIU transportation tariffs are so onerous.

d. Commission Conclusion

The Commission has considered the arguments for and against a small volume transportation tariff and concludes that the proposal has merit. Staff has persuaded the Commission that a simple straight forward transportation tariff for customers eligible for service under each utility's GDS-2 and GDS-3 rate classes is reasonable, including small seasonal customers taking service under GDS-5 who are otherwise eligible for service under GDS-2 and GDS-3. The tariff, which may be either part of Rider T or a separate tariff, shall provide for monthly balancing and not require daily metering. The Commission does not perceive a need at this time for anything more than monthly balancing for smaller customers. No metering charge should be assessed beyond what these smaller customers would need for system supply service. As discussed above, smaller transportation customers will have an option of utilizing daily telemetry. The Commission anticipates that this determination will make transportation service more available to small customers. The Commission would welcome an evaluation of the small volume transportation tariff from AIU, Staff, or any interveners in AIU's next gas rate cases.

8. 12-Month Notification for Seasonal Customers

a. AIU's Position

Both AIU’s existing tariffs and its proposed Rider T require customers to notify AIU by July 1 of each year if they wish to change to or from transportation service effective the following November 1. Because the order in this proceeding will come after July 1, 2008, AIU proposes a later date for the year 2008 by which a notice of service change must be given. Specifically, eligible customers must provide notice of their choice by the later of October 17, 2008 or 14 days after compliance tariffs become effective.

As a compromise, AIU proposes, due to the unique nature of grain dryers, to change seasonal rate class GDS-5 to require notification to AIU by April 1 to be effective August 1 of the same year. The general tariff requirement to remain on this rate for 12 months would not change. AIU believes that the proposed offer to change the notification date to April 1, with the sales service to be effective August 1 of the same year, would resolve the timing issue identified by GFA. AIU clarifies that it will continue to offer other transportation customers the one-time right to change the election for sales service before October 17, 2008, and will notify customers of this option through e-mail and AIU's internet-based USMS, which is an on-line management software system used to maintain daily usage, nominations, and billing information.

In making the proposed compromise to require notification by April 1, AIU does not fully accept Staff's position or any of GFA's various proposals. Rather, AIU contends that its proposal represents a reasonable accommodation to certain seasonal users, such as grain dryers and some asphalt plants, with production in later summer and fall. Expanding the notice compromise to all customers with low winter usage, as Staff and GFA propose, or to all customers who qualify for GDS-5 (as opposed to those who take service under the tariff) is not appropriate, according to AIU. As AIU witness Glaeser explains, off-seasonal use transport customers can create detrimental system impacts if not managed properly. Some of the firm transportation capacity contract levels for AIU ratchet down during the shoulder months, including September and October, when grain dryers typically have heavy usage, in order to follow the load shape of the system sales customers. Additionally, AIU states, this transportation capacity is used at high load factors during the shoulder months and summer to transport gas supply for storage injections into off-system and company owned storage facilities. AIU asserts that capacity for its systems can and does become constrained throughout the year, not just during the peak winter season. AIU contends that this is evident by the pro-rata reductions in primary firm transportation capacity on Panhandle Eastern in May 2008. As a result, AIU claims that allowing all customers with low winter usage to provide 4 months notice, as proposed by Staff (or 30 days as proposed by GFA) would be detrimental to AIU's planning for winter season usage. An April 1 notification date, for service on August 1, would address the GFA's concerns about the impact on grain dryers during the drying season. Therefore, AIU concludes that its compromise to change the seasonal rate class GDS-5 to require notification to AIU by April 1 to be effective August 1 of the same year is reasonable and should be adopted.

b. Staff's Position

While AIU's July 1st notice proposal makes sense for those customers needing to use most of their gas during the winter months, Staff states that it makes little sense for customers who will have little impact during those same months. Therefore, Staff witness Sackett recommends that all customers with less than 5% of annual usage occurring during December through March be required to provide a four-month advance notice before moving between system and transportation service regardless of the GDS that they take service under. Mr. Sackett's four-month notice proposal preserves the four-month notice period currently in effect and in proposed Rider T. Staff asserts that this proposal allows for notice to be provided at the beginning of the injection season for grain dryers.

Staff understands AIU to have accepted at least part of Staff's recommendation. Staff notes, however, that there are two important distinctions between AIU's proposal and Mr. Sackett's recommendation. AIU's proposal only addresses those customers on GDS-5 and it will be for April 1st instead of four months. Mr. Sackett's proposal would apply to all customers with less than 5% of annual usage occurring during December through March and would be a four-month notice. Thus, AIU's proposal would only benefit grain dryers with the four months and not work for other seasonal users whose usage does not pattern the grain dryers. AIU witness Glaeser admitted that his

proposal does not address all of Mr. Sackett's concerns. Since AIU acknowledges that its position does not address all of Staff's concerns, Staff argues that AIU's proposal should be rejected and Staff's should be adopted.

c. GFA's Position

GFA finds the October 17, 2008, special one-time notice offer under proposed Rider T a problem for grain dryers for the 2008 harvest, which will already be in progress, if not nearly over. Even more importantly, for off-season users, the proposed on-going July 1 notification is a major problem beyond 2008, according to GFA. GFA is concerned because AIU's proposal requires grain dryers to give notice two harvests in advance. For example, the September-October, 2010, harvest is within the 12-month period beginning November 1, 2009, and ending October 31, 2010. As proposed by AIU, GFA states that GDS-2 and GDS-3 customers would be required to give AIU notice regarding the 2010 harvest by July 1, 2009. That notification date, July 1, 2009, occurs before the 2009 harvest. AIU's proposed notice requirement results in small and intermediate grain dryers having to give notice two harvests in advance. GFA complains that this proposal will require grain dryers to decide by July 1, 2009 their gas usage that will not begin until some 14 months later, in September of 2010. GFA avers that attempting to make that determination so far in advance will be difficult and risky. Rather than take that risk, GFA states that many grain dryers will likely just change to AIU supply. GFA maintains that the notification requirement is yet another method by which AIU is attempting to influence transportation customers to switch to AIU supply.

GFA states further that AIU will not offer to GDS-3 and GDS-4 customers the reasonable notification requirements available to GDS-5 customers. GFA observes that for seasonal GDS-5 customers, AIU has offered to change the notification requirement to April 1 to be effective August 1 of the same year. GFA asserts that does not solve the issue for smaller to intermediate seasonal use grain dryers. Unless and until AIU's GDS-5 tariff is designed for small and intermediate, as well as large users, GFA states that most dryers with seasonal use that qualify for GDS-5 can not economically take GDS-5 and therefore take service under GDS-2 or GDS-3 tariffs. Those GDS-2 and GDS-3 customers are not being offered the April 1 notification to be effective August 1, despite having the same seasonal use pattern as GDS-5 customers.

GFA proposes that the GDS-5 notification provision (April 1 notice to be effective August 1) be applicable not only to GDS-5 seasonal customers, but to all seasonal customers that qualify for GDS-5, whether or not they choose to take service under GDS-5 (such as grain dryers who choose to remain on GDS-2 or GDS-3). GFA suggests that this proposal would eliminate the discrimination against small and intermediate seasonal users. Alternatively, GFA proposes that seasonal use customers, with less than 5% of annual use in the months of December through March, should not be required to stay on transportation service for 12 consecutive months. Instead, such users could stay on transportation service through March if transportation service commences after December 1 and before April 1. GFA states that both of these

solutions would alleviate the harshness imposed with the two harvest notice requirements proposed by AIU.

d. Commission Conclusion

At a minimum, grain dryers under GDS-5 should be allowed to provide notice by April 1 of each year whether they intend to be a transportation customer or sales customer beginning August 1 of that same year, on which AIU, Staff, and GFA all appear to agree. Whether other seasonal users of gas eligible for service under GDS-5, regardless of whether they actually take service under GDS-5, should be able to operate under the same notice provisions is less clear. AIU appears to have legitimate capacity concerns in conjunction with allowing all small and intermediate seasonal users to provide April 1 notice of a switch between sales and transportation service. Although the Commission does not adopt such a broad application of the April 1 notice provision in this proceeding, the Commission is interested in considering this idea further and invites discussion of it in AIU's next gas rate cases. In the meantime, however, given the nature of grain dryers' seasonal use, the Commission finds that grain dryers under GDS-2 and GDS-3 should also be allowed to provide such notice by April 1 of each year, for the period beginning the following August 1. With regard to waiving or modifying the general tariff requirement that grain dryers remain on the rate for 12 months, the Commission is not prepared to do so at this time in absence of assurances that gaming would not occur.

9. Minimal Winter Use Delivery Service Provisions

a. AIU's Position

With respect to AmerenCIPS, AIU proposes removing the Minimal Winter Use delivery service provisions from the present Rate 3 and Rate 4. With respect to AmerenCILCO, AIU proposes removing the Minimal Winter Use delivery service provisions from the present Rate 600. In both instances, AIU proposes to include such language in its proposed new GDS-5 -- Seasonal Gas Delivery Service.

AIU also asserts that upon reviewing Staff's Initial Brief, it learned of several new and significant changes in gas rate design related to “seasonal load” being recommended by Staff (discussed below). AIU states that Staff's recommendations lack supporting citations to the record as to their scope, applicability, or impacts on all affected customers. AIU goes on to state that the novel changes recommended by Staff are extremely problematic as well as markedly vague. All of the recommendations related to changes to accommodate “seasonal load.” AIU contends, however, that Staff fails to provide a definition of “seasonal load” in its Initial Brief. Because natural gas is used for heating, AIU observes that a large number of all customers use natural gas seasonally. AIU maintains that it is unclear from Staff’s recommendation what the parameters of “seasonal” use would be.

Additionally, AIU avers that converting demand charges to volumetric charges involves a major change in rate design elements. AIU also notes that a major theme in Staff's rate design testimony is its assertion that all rates for customers should increase equally across-the-board to the extent feasible. AIU argues that converting a demand charge to a volumetric charge is inconsistent with that theme because doing so will result in unequal customer impacts. Finally, AIU insists that Staff's assertion that AIU has not provided credible support for why customers should require demand charges is incorrect. AIU contends that it provided ample expert testimony on the subjects of telemetry and the inappropriateness of eliminating demand rates.

b. Staff's Position

In response to AIU's proposal to include the Minimal Winter Use delivery service provisions in GDS-5, Staff witness Harden agrees that doing so is an appropriate means of conforming AIU's gas rate classes with its electric rate classes since it would not result in unequal bill impacts for individual gas customers. In its Initial Brief, Staff also voiced support for various GFA proposals concerning seasonal usage. GFA argues that seasonal customers do not place constraints on the system and therefore should not be assessed a demand charge. GFA also wants a volumetric charge for any customer with a seasonal load profile. GFA proposes that it should not be required to have daily balancing and telemetry as well. AIU witness Glaeser presents a counter-argument concerning an isolated incident where on one captive system, a single seasonal customer, has more than half of the load on that system.

Staff contends that AIU is attempting to use anecdotal evidence to prove that it must take a certain course of action. In this situation, however, Staff argues that AIU's example is not even close to being representative of the typical grain dryer. The one customer that it used, Staff notes, was not even a grain dryer. Another reason that Staff believes that AIU's response should be dismissed is because the issue is not directly related to these customers being transportation customers. Staff contends that the situation of the customer Mr. Glaeser used in his example would be the same if it were a sales customer, because its load is still unpredictable and the size of its usage relative to the captive system load would not change. Some exceptions may require daily metering, but AIU has provided no reason to conclude that most seasonal customers place such a load on the system that they need either daily balancing or telemetry, according to Staff. Staff therefore recommends that the Commission adopt GFA's proposal that customers with a seasonal load should not be required to balance daily and have daily telemetry regardless of which GDS they would otherwise be on. Also, because AIU has failed to provide a credible rationale for why seasonal customers should have demand charges, Staff recommends that the customers who would not be required to have a demand charge under the non-seasonal GDS classes, should not face a demand charge under GDS-5.

c. GFA's Position

GFA recommends that the demand charges in GDS-2 and GDS-3 be converted to volumetric charges, a recommendation which AIU opposes. GFA argues that non-winter seasonal use customers do not place constraints on the AIU distribution system, and therefore should not be charged a demand charge. GFA states further that AIU has not provided evidence that a demand charge, particularly a year-round demand charge, is appropriate for customers with minimal winter use (less than 5% of annual usage occurring during December through March). GFA observes that Mr. Glaeser uses a single anecdotal example of a seasonal customer on a captive part of the AIU distribution system (one pipeline supply). Because AIU's distribution system capacity is obviously underutilized during non-winter periods, GFA asserts that there is no justification for AIU to require demand charges for small and intermediate use customers with minimal winter use. GFA finds Staff's reasoning sound when it recommends that customers who would not be required to have a demand charge under the non-seasonal GDS rate schedules should not face a demand charge under the GDS-5 seasonal rate.

d. Commission Conclusion

AIU's proposal to include the Minimal Winter Use delivery service provisions from AmerenCILCO's Rate 600 and AmerenCIPS' Rates 3 and 4 in the new proposed GDS-5 does not appear to be opposed by any party. This proposal is reasonable in the Commission's opinion and is adopted. Other issues under this heading are less clear.

The elimination of the demand charge for non-winter gas customers as well as minimal winter use customers is an intriguing idea, but without more information, the Commission is not prepared to adopt these proposals at this time. One concern that causes the Commission to hesitate in adopting this proposal is the uncertainty surrounding the degree to which non-winter gas users affect the apparently increasing non-winter demand for gas. The ease/difficulty of converting demand charges to volumetric charges is another area of concern for the Commission. Without knowing more about how this would be accomplished, the Commission is reluctant to direct that it be done. The Commission invites further discussion on these issues in AIU's next gas rate cases.

With regard to daily balancing and telemetry for customers on GDS-5, the Commission is not persuaded at this time that such are not appropriate for larger sales or transportation seasonal customers. Accordingly, the Commission rejects Staff's and GFA's proposal that larger seasonal customers be free of any requirement to use daily balancing and telemetry. As discussed above, however, in the general discussions of daily telemetry and a small volume transportation tariff, the Commission is of the opinion at this time that daily balancing and telemetry are not necessary for transportation customers who would otherwise be GDS-2 and GDS-3 sales customers. Similarly, the Commission does not believe at this time that GDS-2 and GDS-3 sales customers should be required to provide daily balancing and telemetry. In the absence of any

persuasive arguments to the contrary, the Commission sees no need for daily balancing and telemetry for such smaller seasonal customers.

10. Uniform Terms Among Tariffs

GFA witness Adkisson is troubled by the fact that GDS-2, GDS-3, GDS-4, and GDS-5 have differing maximum use qualifications among the three utilities. He suggests implementing uniform use qualifications among corresponding GDS rates for all three utilities. GFA notes that AIU cites the need for rate continuity and stability, as well as the need to make changes gradually. Although AIU proposes continuity and stability here, GFA asserts that AIU abandons those principals when it wants to make tariff changes. GFA contends that AIU's inconsistencies point to its attempts to influence customers toward AIU supply.

AIU does not find GFA's concerns on this issue valid. AIU states that its rate design objective was to conform rates to the maximum extent possible while still maintaining rate continuity and stability. According to AIU, Mr. Adkisson's recommendation to conform the GDS rate qualification provisions among the three utilities might compromise the AIU rate continuity and stability goal.

AIU points out that Mr. Adkisson provides no analysis of the effects (i.e., customer rate migration, revenue instability, customer bill impacts, or cost analysis) of his proposed recommendation. Without thorough analysis, AIU fears that constructing a different rate design would inappropriately expose it to possible revenue erosion and run counter to the way rate classifications are set today. AIU maintains that GFA's recommendations will require a complete analysis of the affected service classifications to determine realignment of class billing determinants, and also require estimates and assumptions made for expected customer migration.

If the Commission agrees with Mr. Adkisson's rate design recommendation, AIU states that the final rates would need to be developed only after a detailed analysis of the recommendation, so as to determine the respective billing units for each affected service classification. The determination of billing units would also need to take into consideration the effects of rate migration, if any. AIU argues that this process would be necessary to ensure that, at the end of the day, the compliance rates filed in the case provide AIU with a reasonable opportunity to earn the rate of return granted in this case. AIU adds that the Commission would have to allow adjustments to other rates in order for the utilities to make-up any revenue shortfall created by his proposal.

The Commission understands GFA's concern. While some consistency exists among the maximum use qualifications for the GDS-2, GDS-3, GDS-4, and GDS-5 rate classes among the three utilities, obvious inconsistencies also exist. The Commission would also prefer that these tariffs be much more similar. Because this is the first "incarnation" of the GDS rate classes and because no analysis of the effects of more uniform GDS rate classes has been done, however, the Commission is not prepared to direct that AIU implement uniform maximum use qualifications for the GDS-2, GDS-3,

GDS-4, and GDS-5 rate classes among the three utilities in this proceeding. Instead the Commission directs AIU to study the impact of GFA's proposal prior to its next gas rate case. If AIU finds that greater uniformity is warranted, its rate filing should reflect the results of that study. If AIU finds that greater uniformity is not warranted, it should be prepared to explain why and provide the results of the study if asked during the discovery process.

11. Weather Normalization

AIU calculated billing determinants in this case based on 10-year weather normalized averages. AIU witness Laderoute presents testimony showing that 10-year normals are a better predictor and more representative of "normal" weather than 30-year normals in this case. He conducted a number of detailed statistical tests that are used by meteorologists and climatologists in studying weather and normals to test the validity of this conclusion, using historic National Oceanic & Atmospheric Administration weather data for Champaign-Urbana. AIU states that no party challenged the validity of Mr. Laderoute's testing, data, or conclusions.

In his direct testimony, Staff witness Sackett concluded that AIU's proposal to use a shorter weather period was acceptable, but recommended that AIU provide a weather study similar to that used in the Peoples/North Shore gas rates cases, Docket Nos. 07-0241 and 07-0242 (Cons.). He indicated that the weather study should provide additional weather normalization data sets between 8 and 12 years in length, and compare such sets with a 30-year data set to determine the predictive quality of each set. Mr. Sackett requested the information because he understood the Order in Docket Nos. 07-0241/07-0242 (Cons.) to require him to do so. Mr. Laderoute provided the requested data and analysis in his rebuttal testimony, and concluded that the 8-, 11-, and 12-year normalized data sets are comparable to the 10-year normals in this case, and are therefore more predictive than the 30-year normal results presented in his direct testimony. Mr. Sackett agrees that AIU's approach is reasonable and not inappropriate.

The only issue to address is whether the Order in Docket Nos. 07-0241 and 07-0242 (Cons.) requires all utilities in the future to provide additional data sets and compare such sets with a 30-year data set to determine the predictive quality of each set. AIU does not believe that the Commission has required utilities in all future rate cases to provide a range of data to support their chosen weather normalization period, to determine which is the most predictive. AIU contends that this interpretation would be cumbersome and unnecessary. AIU acknowledges that the Commission adopted a more predictive approach to weather normalization in Docket Nos. 07-0241 and 07-0242 (Cons.), to further the Commission's goal of setting "rates with the greatest likelihood of generating the Utilities' allowed annual revenues." (Docket Nos. 07-0241 and 07-0242 (Cons.), Order at 123) Mr. Laderoute's recommendations, AIU adds, are consistent with this goal.

Understanding the background associated with this issue may facilitate discussion. In the Peoples/North Shore rate case, the Commission noted that it would

have expected a 30-year data set to be more predictive, based on the general statistical principle that more data regarding varying conditions is better than less. But after having considered the 8-, 11-, and 12-year normals, as well as the evidence presented in Nicor's most recent rate case (Docket No. 04-0779), the Commission concluded that there was no stable long-term trend in weather that would justify adhering to a 30-year normal. Furthermore, in adopting a 10-year normal in the Peoples/North Shore case, the Commission did not adopt the most predictive weather data set. In that case, the Commission made a decision between the most predictive data sets presented in light of all of the evidence.

In this case, AIU has shown that 11-year normals appear to be the most predictive set, but that adoption of 10-year normals presents a similarly predictive result and is reasonable in this case. Although Mr. Sackett agrees with Mr. Laderoute, Staff asserts that AIU provided no reason why a 10-year normal is as good as or better than the 11-year normal. AIU merely concludes that because the 10-year falls between the 11-year and 8-year normal in length that it was, "on balance," appropriate. AIU also notes that all of its billing determinants and resulting rate design data in this case are based on 10-year weather normalized data. Parties have not had the opportunity to review and respond to rate design evidence developed using alternative heating degree days, from alternative weather norm data sets.

While Staff recognizes that the Commission is not bound by its prior decisions, it still maintains that all utilities must provide the additional weather data discussed in Docket Nos. 07-0241 and 07-0242 (Cons.). Staff points out that the Commission required that all subsequent rate cases follow the procedures it adopted in that case, stating that, "In subsequent rate cases, we will expect utilities to employ the principles and methods approved here or bear the burden of proving that additional measures will materially enhance the alignment of allowed and actual revenues." (Order at 125-126)

The Commission concludes that AIU's use of a 10-year weather normalized average is acceptable and is hereby approved. The Commission also appreciates Staff's observance of the conclusion on weather normalization in Docket Nos. 07-0241 and 07-0242 (Cons.). While it is correct that the decisions of the Commission are not res judicata, nothing prevents Staff or the Commission from recognizing the value of an earlier decision and applying the same principles to another proceeding. In this instance Staff sought additional information consistent with the weather normalization conclusion in the Peoples/North Shore Order in order to ensure that use of 10-year averages is appropriate. AIU provided the information and the primary question was resolved. To facilitate the resolution of this issue in future AIU rate cases, the Commission directs AIU to provide comparable data sets as it did in this proceeding with its initial filing. Staff is not barred from seeking other data sets for comparison purposes.

12. Imbalance Trading

a. AIU's Position

Prior to its decision in this proceeding to offer banking, AIU offered to provide an imbalance trading mechanism to transportation customers. AIU witness Glaeser explained that a transportation customer or marketer could monitor its imbalance position during the month through the USMS. Mr. Glaeser further explained that transportation customers could choose to contact another transportation customer or marketer served from the same interstate pipeline and trade off-setting imbalances. The parties involved in the trade would be required to provide confirmation that the trade, in fact, had been agreed upon. Thereafter, AIU would change each customer's imbalance position within the USMS. Mr. Glaeser went on to testify that modifying the USMS system in order to accommodate imbalance trading would take time, as significant software changes are needed.

AIU now contends, however, that subsequent developments in this proceeding have eliminated the need for the imbalance trading service. The imbalance trading mechanism was intended to help transportation customers and marketers manage daily imbalances in order to minimize daily and monthly cash-out charges. As Mr. Glaeser explains in his surrebuttal testimony, AIU is now proposing to offer banking services which satisfies the same objective. AIU adds that with the offer of banking services, the imbalance trading service is no longer needed since the bank balance can be transferred between transportation customers and marketers. Mr. Glaeser also explains that bank limit balances between transportation customers served by the same interstate pipeline are transferable after confirmation from both counterparties. As AIU moves from the current bank services offered under the existing tariffs to those that it now proposes, AIU states that any balance in excess of the new bank limit maximums will be cashed out at the average of the Chicago City Gate first of the month price for the prior 12-month period after the customer avails itself of any bank balance trading with other customers. Consequently, because proposed banking service fulfills the same purpose as imbalance trading service, AIU withdraws its imbalance trading proposal and urges the adoption of its proposed banking service.

AIU notes CNE-Gas' concern that the bank services may not sufficiently make up for the absence of imbalance trading. In response, AIU states that the requisite functionality will be provided. AIU also asserts that CNE-Gas' effort to tie AIU to a Peoples tariff should be disregarded. According to AIU, there has been no factual demonstration to show that AIU's systems can accommodate the specifics associated with the Peoples tariff.

b. Staff's Position

Staff understands that AIU is withdrawing its proposal to provide for imbalance trading on the grounds that it is no longer necessary in light of AIU's newly proposed bank balance trading. Staff states that AIU's proposal to trade bank balances does not

directly affect the daily imbalances that customers face. Staff witness Sackett, however, agrees that, with any of the bank proposals, the need for imbalance trading is limited.

c. CNE-Gas' Position

CNE-Gas understands that AIU has withdrawn its imbalance trading service since AIU does not believe it is necessary with a banking service. CNE-Gas is concerned by this change but acknowledges that once actual tariff sheets setting forth the terms and conditions of the banking service are available for examination, the transfer of bank limit balances may provide some of the imbalance trading that transportation customers functionally require. Although the operation of imbalance trading may be different with and without a storage bank, CNE-Gas asserts that imbalance trading remains a valuable tool for transportation customers. CNE-Gas' concern is that even with storage banks, transportation customers need to have the ability to trade their bank imbalances with others. Whether this is called "Imbalance Trading" per se is not important to CNE-Gas; what is critical is that the functionality exists. CNE-Gas seeks functionality on par with that described in the Peoples/North Shore Order.

Although under the Peoples/North Shore Order imbalance trading is not allowed between customers of different utilities, for instance between customers of Peoples and North Shore, CNE-Gas indicates that there are no additional restrictions related to upstream pipelines. CNE-Gas states that this is one key distinction between imbalance trading, as discussed in the Peoples/North Shore Order, and the transfer of bank limits mentioned in Mr. Glaeser's surrebuttal testimony. Since imbalances offset one another under imbalance trading, CNE-Gas contends that AIU should be indifferent and there is no adverse impact on utility operations. CNE-Gas recommends that the Commission direct AIU to include imbalance trading, similar to the Peoples/North Shore Order described above, in its transportation tariffs.

d. Commission Conclusion

The Commission recognizes the value of imbalance trading to transportation customers. But given the adoption of gas banking services above, the Commission does not believe that imbalance trading is necessary under the circumstances. If circumstances change in future AIU rate cases, the Commission will again consider requiring imbalance trading.

13. Purchase/Confiscation of Customer-Owned Gas

a. AIU's Position

AIU's existing tariffs provide AIU the right to purchase gas owned by transportation customers in a situation where system integrity is threatened and the system emergency requires curtailment. AIU proposes similar language in its proposed Rider T. Under its proposal, AIU would first attempt to acquire the transportation

customer gas through a voluntary purchase. If a voluntary purchase does not occur, proposed Rider T provides that AIU may confiscate the gas at price of 110% of the daily market price.

While CNE-Gas understands that AIU may need to acquire customer-owned gas in an emergency, it is still troubled by the idea of a forced sale of transportation gas even if a 10% premium is included. To address such concerns, AIU's current proposal contains three conditions that must be met before AIU has the right to purchase gas owned by transportation customers. First, system integrity is threatened. Second, the utility has declared a Critical Day. Third, the utility implements curtailment of natural gas service to customers pursuant to the Curtailment Plan. AIU contends that these conditions ensure that it will not arbitrarily acquire gas from its transportation customers without good reason and will exercise this right only under the most severe circumstances. AIU states further that the right to purchase gas owned by transportation customers would not be allowed only on a critical day since all three conditions must be met before purchasing customer gas. In addition, the proposed tariff states "the Company's right to purchase gas owned by a Customer shall be exercised by the Company only after the Company has exhausted reasonable efforts to obtain the necessary gas supplies from other sources . . . ." (Ameren Ex. 30.0 at 30-31)

In response to CNE-Gas' assertion that involuntary confiscation of transportation gas supplies will not increase the volume of gas that is flowing during a curtailment, and therefore no relief will be provided, AIU asserts that CNE-Gas misunderstands how the process works. AIU witness Glaeser explains that volumes of gas delivered into the system during a curtailment will likely not be increased by confiscation; however, the needed relief is still provided. The gas purchases only occur during curtailment, during which customers will be required to reduce usage by customer class so that the demand on the system will be lower. The gas purchased from the transportation customers at the city gate delivery points will be then used to serve high priority residential and human needs customers, since the larger customers will have been curtailed.

If confiscation occurs, CNE-Gas argues that AIU should waive any balancing costs or penalties incurred due to any imbalance created when transportation customer gas is purchased during curtailment. AIU does not agree and argues that if a customer is complying with the curtailment, the imbalance will be minimized. AIU states that it would not buy any gas from transportation customers unless they have been curtailed, which means their usage has been reduced. If there is more than a minimal imbalance, AIU maintains that the customer has not complied with the curtailment and should incur all imbalance charges as well as penalties. If these costs and penalties are waived, AIU asserts that there is no incentive to a customer to reduce its usage, thereby defeating the purpose of the curtailment and thus threatening system integrity.

In response to any suggestion that confiscation of gas, even with a 10% premium, constitutes a conversion under 810 ILCS 5/7-404, AIU argues in its Reply Brief that this section of the Illinois statutes is inapplicable to that situation. Moreover, if

such tariffs are approved by the Commission, AIU asserts that it would be difficult to claim that the tariffs are unfair since it is the Commission that determines what is fair in this proceeding. Taking the CNE-Gas position regarding conversion to its logical extreme, AIU contends that no gas utility could ever curtail or interrupt a transportation customer no matter what the circumstance. AIU also does not see the relevance of CNE-Gas' FERC discussion.

b. Staff's Position

AIU initially sought the right to purchase customer gas at market price on a critical day. Staff witness Sackett objects to this because he believes that AIU should attempt to purchase gas from transportation customers in voluntary transactions before confiscating gas from customers. CNE-Gas proposes that, at a minimum, a 10% premium be applied to the market price for that purchase. Mr. Glaeser then proposed a voluntary purchase offer first, and then confiscation at a 10% premium over the market price. Mr. Sackett accepts this proposal.

c. CNE-Gas' Position

CNE-Gas objects to any forced sale of customer-owned gas, no matter the circumstances. Confiscation of customer-owned gas, CNE-Gas opines, would likely constitute conversion under Illinois law. CNE-Gas reports that Section 7-404 of the Uniform Commercial Code (adopted as 810 ILCS 5/7-404 (2008) in Illinois) states that a bailee is not liable for delivering goods to a person who did not have authority to receive the goods if the bailee acts in good faith. However, the commentary to the provision states that "[g]ood faith now means 'honesty in fact and the observance of reasonable commercial standards of fair dealing,'" UCC §7-404 cmt. purposes (2007). CNE-Gas contends that AIU's confiscation of customer-owned gas would be unlikely to be considered good faith under this standard because AIU would have knowledge that the supplier did not wish to sell the gas to AIU. (See Bishop v. Allied Van Lines 3 Dist., Inc., 399 N.E.2d 698, 701 (Ill. Ct. App. 1980) (holding that a bailee did not act in good faith and did not observe commercially reasonable standards when the bailee delivered the goods with knowledge of adverse claims between the bailors)).

Similarly, CNE-Gas states that FERC has required interstate pipeline tariff provisions that provide for the seizure of gas by the pipeline to be removed from tariffs if a customer fails to abide by a curtailment or interruption notice. (See, e.g., Guardian Pipeline, L.L.C., 91 FERC ¶61,285 at 61,987 (2000); TriState Pipeline, L.L.C., 88 FERC ¶61,328 at 62,006 (1999); Steuben Gas Storage Company, 72 FERC ¶61,102 at 61,543 (1995))

CNE-Gas also argues that because AIU does not propose to waive penalties for actions taken by transportation customers in support of a curtailment order, the confiscation of customer-owned gas supply leaves the transportation customer at risk of receiving a price of only 90% of index if it delivers excess supply, while nominated volumes are sold to the utility at 110% of index, even though both actions alleviate the

curtailment. Even at the 110% index price, CNE-Gas states that transportation customers could be forced to sell gas to the utility at a financial loss, depending on the purchase price, which may not be index-based. As the daily market price is based upon the price that gas traded at the morning prior to flow, CNE-Gas contends that it is likely that by the time the Critical Day takes effect, as no advance notice must be provided, the daily market price from the previous day is no longer representative of the market price at that point in time when the gas is seized. The mechanics of this ultimately depend upon the exact storage, cashout, and balancing tariffs approved in this proceeding and since no draft tariffs exist for any of the current proposals offered, CNE-Gas simply requests that if the Commission approves the confiscation of the customer's gas supply, the customer should not be assessed any charges or penalties due to any positive imbalance that is created following a forced sale.

CNE-Gas states further that transportation customers and their suppliers may also have the option to secure additional gas supply. AIU's proposed tariff, CNE-Gas complains, does not accommodate such action. Instead such action could be met with additional costs and penalties from AIU, even though additional gas supplies on a Critical Day is precisely the outcome AIU desires. Consequently, if AIU's proposal is approved, CNE-Gas asserts that transportation customers should not be penalized or charged for delivering additional gas supplies under such circumstances. CNE-Gas urges the Commission to require waiver of such additional costs.

d. Commission Conclusion

At the outset, the Commission must state that it does not anticipate that AIU will often need to purchase or confiscate gas owned by transportation customers in order to preserve system integrity. In a well maintained and managed system, such circumstances should occur infrequently. Purchasing or confiscating customer-owned gas should be, and appears to be, viewed by AIU as a last resort to stave off an emergency.

The less extreme of the two options for avoiding an emergency is obviously a voluntary purchase. The Commission agrees with and approves of the notion that AIU should first attempt to negotiate a price for customer-owned gas that it seeks to acquire. In the event that a voluntary purchase can not be negotiated, the Commission also agrees that AIU should be able to confiscate customer-owned gas under reasonable terms in order to prevent harm to the gas distribution system. The Commission has considered CNE-Gas' claim that confiscation of customer-owned gas violates Section 7-404 of the Uniform Commercial Code, but does not find this statute applicable.

If AIU is permitted to purchase customer owned gas, CNE-Gas also argues that the transportation customer should not be penalized for any imbalances resulting from the associated curtailment. The Commission agrees with CNE-Gas to the extent that the imbalance is one where the transportation customer delivers more gas into the system than is used for this is exactly what a struggling system needs. If a transportation customer uses more gas than it delivers into the system, then the

imbalance penalties should apply. As for the price of confiscated gas, the Commission is concerned that paying the transportation customer the market price of gas traded at the morning prior to flow may not be reasonable. If circumstances are such that curtailment and a Critical Day are occurring, the market price of gas may be quite higher than what it was the morning prior to flow. Therefore, the Commission concludes that the price to be paid for confiscated gas should be equal to the 8:00 AM index price reported by Platt's *Gas Daily* Midpoint for Chicago Citygates on the Critical Day. A 10% premium shall be added, as agreed to by AIU. This result should address transportation customers' concerns about receiving a fair price for confiscated gas.

14. Critical Day and Operational Flow Order Notice Provisions

a. AIU's Position

AIU proposes to include both Critical Day and OFO language in gas tariffs. AIU witness Glaeser explains that an OFO is an order which the utility may declare or issue to a customer group or to specific customers in order to alleviate problematic operating conditions. He also indicates that the new Rider T includes the Critical Day declarations. Mr. Glaeser identifies a number of circumstances that could cause the declaration of a Critical Day. The “common driver” is that on-system or up-stream resources used to operate and maintain system integrity are under duress, threatening the integrity of the distribution system and the ability to deliver gas to all customers. AIU states that OFOs and Critical Day provisions are common place in the natural gas industry, including the interstate pipelines to which AIU is connected, and are necessary to ensure the integrity of the delivery system. AIU proposes that transportation customers be notified of an OFO or Critical Day through formal notification such as telephone, fax, or e-mail. The utility would also post such a declaration on its USMS website, which is utilized by transportation customers and their marketers for routine operations. Mr. Glaeser also identifies the various penalties and charges that would be issued in the event an OFO or Critical Day was violated. He explains that a series of tiered penalty charges tied to the severity of the event are being proposed and identified the three penalty charges as: OFO Balancing Charge, Unauthorized Gas Use Charge, and Critical Day Imbalance Charge. Mr. Glaeser also testifies as to the manner by which these charges would be assessed.

AIU notes that only CNE-Gas responds to AIU's OFO and Critical Day positions. Specifically, CNE-Gas is concerned with the lack of no advance notification requirements and argues that some parameters should be placed in the tariff to provide guidance for the type of advanced notice that the utilities will provide to the transportation customers and their suppliers. In response, Mr. Glaeser testifies that AIU is willing to provide a 2-hour prior notice before implementing an OFO against any customer or group of customers. He also testifies that as much notice as practical would be given to customers in the event of a Critical Day but that a defined time frame could not be provided due to the unexpected nature of the events that lead to a Critical Day declaration. As an example, Mr. Glaeser observes that a pipeline rupture foregoes any meaningful opportunity for an extended notice. He concludes nonetheless, that it is

in AIU's best interest to give as much notice as practicable since the purpose is to notify transportation customers to modify their supply deliveries and/or gas consumption to help maintain system integrity.

AIU notes that CNE-Gas disagrees that 2 hours is sufficient and asserts that Nicor provides notification of a Critical Day at least 25 hours in advance and Peoples provides 23½ hours notice. CNE-Gas is perplexed as to why AIU can only provide 2 hours notice of an OFO and no commitment to advance notification for a Critical Day. To facilitate understanding of AIU's position, Mr. Glaeser proffers an example that demonstrates the concerns to committing to more than the 2-hour notice for an OFO and no prior notice period for a Critical Day. The AmerenCIPS Metro-East system distributes natural gas to Alton, Illinois and adjacent areas. This captive system serves approximately 18,000 customers and is connected to one interstate pipeline – Mississippi River Transmission Corporation – through the Federal Station and Chessen Lane Interconnections. The AmerenCIPS Metro-East system has no on-system storage. If the Federal Station interconnect facility experienced a pipeline rupture on a normal winter day, all 18,000 customers on the system would rapidly lose pressure within minutes. This would happen because Chessen Lane is a significantly smaller interconnect and can not supply the entire AmerenCIPS Metro-East system under normal winter load conditions. By issuing an immediate Critical Day and quickly implementing curtailment procedures, the system could be protected from a widespread outage by curtailing the largest customers before the entire system collapsed. The Chessen Lane station may be able to maintain system deliveries and pressure if the major industrial customers on the system shut down quickly. AIU argues that it is not practical to give any notice in this emergency situation to maintain system integrity – much less 24–hours' notice. AIU insists that it is, therefore, essential that it has the ability to issue a Critical Day without advance notice.

Of course, as stated in the tariff, AIU indicates that it will provide advance notification if possible, but providing advance notice may not be practical or even possible in certain situations. AIU asserts that the tariffs should reflect operational realities--and the reality is that advance notification can not always be given when a system emergency occurs. AIU maintains that CNE-Gas inaccurately compare AIU's notification period to Nicor and Peoples. Although all utilities could have ruptures on their systems, AIU contends that there may be differences in the resources available to recover from pipeline ruptures. AIU states that some utilities may have hub services readily available, while others may have fully integrated systems – unlike AIU, which has many isolated, captive systems (See Ameren Ex. 54.7, Ameren Illinois Natural Gas Facilities map). AIU speculates that even Nicor's or People's more integrated distribution systems or hub service resources could experience major failures leading to a more immediate crisis than the their tariff language implies. AIU reasons that the different resources available to respond to a system emergency may make the notification period different.

b. CNE-Gas' Position

When declaring an OFO or Critical Day, CNE-Gas argues that the Commission should require AIU to provide reasonable notice. CNE-Gas does not agree that 2 hours notice for OFOs is sufficient and contends that no notice for Critical Days is unacceptable. Certainly if force majeure conditions occur, CNE-Gas acknowledges that the standard notice intervals may require suspension due to extreme circumstances. However, under other OFO and Critical Day circumstances, CNE-Gas argues that transportation customers and their suppliers should receive adequate notification before such a “non-force majeure” event is declared by an LDC. CNE-Gas contends that transportation customers deserve some degree of commitment from a utility that it will attempt to notify them in advance when these conditions occur so the transporter is able to take appropriate action to mitigate potential costs which may be incurred as a result of a Critical Day or OFO. CNE-Gas asserts that the rationale AIU offers for its inability to provide any Critical Day notice is no different than conditions that confront other utilities that offer notice. As discussed above, CNE-Gas observes that other Illinois utilities provide notice more than twenty hours in advance. CNE-Gas recommends that the Commission require AIU to provide OFO and Critical Day notice to customers that is comparable to the terms provided by other Illinois utilities.

c. Commission Conclusion

The Commission agrees with CNE-Gas that when comparing the notice provided by Nicor and Peoples and the notice that AIU proposes to provide, a great disparity seems to exist. 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.

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.

One other area of concern regards AIU's proposed Critical Day definition in Rider T. The fifth condition that may trigger a Critical Day under Rider T is "other market conditions which may warrant such action by the Company." Exactly what "market conditions" may warrant declaration of a Critical Day is unclear to the Commission. The

tariffs of Nicor and Peoples do not appear to share this language. The Commission advises AIU to be cautious in the declaration of Critical Days for market reasons at least until it provides clarification in its next gas rate cases. In any event, the Commission expects AIU to only implement OFOs and Critical Days as last resorts in protecting system integrity.

15. AmerenCIPS and AmerenCIPS Metro-East Rate Areas

Currently, AmerenCIPS has two rate areas, AmerenCIPS and AmerenCIPS Metro-East. In its direct filing, AIU witness Warwick proposed to establish one set of gas tariffs for the entire AmerenCIPS footprint instead of the two current rate areas. Staff witness Harden objects to consolidating these service areas due to the unequal bill impacts for individual gas customers that could result from this change. Mr. Warwick later stated a willingness to accept the Staff position. He notes, however, that the rate conformance would bring about a rate reduction for certain customers under AIU's proposed rates and rate design. While AmerenCIPS agrees to forego rate consolidation at this time, AIU plans to raise the issue again in AmerenCIPS' next gas rate case consistent with Ms. Harden's comments.

The Commission acknowledges AIU's acceptance of Staff's position on this issue, but is nevertheless reluctant to adopt it in light of observations made by AIU in its Brief on Exceptions. AIU does not mean to suggest in its Brief on Exceptions that it is changing its position following its acquiescence to Ms. Harden's concerns, but simply wants to make the Commission aware of the impact on GDS-1 and GDS-2 customers in the AmerenCIPS and AmerenCIPS Metro-East rate areas if the customer charge is to reflect 80% of fixed costs. Using its August 22, 2008, supplemental response to the Administrative Law Judges' post-record data request, AIU explains that the monthly customer charge for GDS-1 AmerenCIPS customers would be $18.03, while the corresponding charge for AmerenCIPS Metro-East customers would be $22.01. If these rate areas are combined, AIU reports that the single GDS-1 monthly customer charge would be $18.43. AIU states further that the monthly customer charge for GDS-2 customers of AmerenCIPS would be $28.10 while that of AmerenCIPS Metro-East would be $56.71. Under a combined rate area, AIU states that the single GDS-2 monthly customer charge would be $29.97.

Even though these charges are somewhat different from those approved in this Order, the Commission is of the opinion that such disparities (particularly for GDS-2 customers) should be avoided when the means to do so is so readily available. Accordingly, for the purpose of the monthly gas customer charge, the AmerenCIPS and AmerenCIPS Metro-East rate areas should be combined for the GDS-1 and GDS-2 rate classes. The fact that these rate areas are to be eventually combined anyway further supports this conclusion.

E. Contested Electric Issues

1. Rate Limiter

a. AIU's Position

AIU recommends that the rate limiters implemented as part of the rate redesign case, Docket No. 07-0165, be modified or eliminated. AIU says that as a result of the rate redesign case, rate limiter provisions were added to DS-3 and DS-4. The total monthly charge for Distribution Delivery and Transformation Charges was limited to no more than 2¢/kWh where 20% or less of the customer's annual usage occurs in the summer months of June through September. The Distribution Delivery Charges for DS-3 and DS-4 were also increased, to maintain revenue neutrality. AIU indicates that Staff and GFA want to maintain the DS-4 rate limiter. AIU complains that neither GFA nor Staff offers an analysis of how much longer these limiters should persist.

AIU proposes that the rate limiter provision for DS-3 be increased proportionate to the average rate-increase for that class, and that the provision for DS-4 be eliminated. AIU says that in Docket No. 07-0165, the Commission ordered that the rate limiter should be in place only as long as necessary. According to AIU, the Commission expected that the parties would, in the instant rate case, be evaluating the period of time the rate limiter needs to be in place to ensure just and reasonable rates.

AIU has proposed moving to an on-peak determinate for establishing demand rates and claims there is no opposition to this proposal. AIU asserts that the GFA essentially asks to retain rate design concessions that, when combined with the move to on-peak demand determinates, would establish benefits for GFA constituents above and beyond those awarded in Docket No. 07-0165. AIU believes eliminating the DS-4 rate limiter would inject fairness by moving rates closer to cost and avoiding the unnecessary subsidization inherent in such limiters. AIU contends that implementation of a rate limiter requires that Distribution Delivery Charges be increased for DS-3 and DS-4 customers. In other words, AIU says Distribution Delivery Charges are higher than they otherwise would be if there was no rate limiter. AIU claims that customers who do not benefit from the rate limiter subsidize customers who receive a benefit. AIU says eliminating the DS-4 rate limiter eliminates this inequity.

According to AIU, IIEC points out that there is no particular distinction for the customer group GFA singles out that warrants a long-standing subsidy. AIU indicates that the Commercial Group offers three reasons for eliminating the rate limiter. The Commercial Group claims that eliminating a rate provision that created intra-class subsidies does not result in unequal treatment; rather it puts all customers within that class on a more equal footing with respect to rates being based on the true cost to serve. The Commercial Group also asserts that in Docket No. 07-0165 the Commission made it clear that the rate limiter is a transitional mechanism for certain customers who were facing large rate increases and that it should only be in place as long as necessary. The Commercial Group also contends that use of on-peak demand

provides an incentive for rate limiter customers to reduce on-peak demands and potentially reduce their bills.

In AIU's view, the move toward on-peak demand determinates should be considered in evaluating the continued need for a DS-4 limiter. AIU proposes to begin using a billing demand applicable to the Distribution Delivery Charge equal to the higher of (a) the maximum on-peak demand in the month and (b) 50% of the highest off-peak demand in the month. Presently, the Distribution Delivery Charge is assessed based on a customer's monthly maximum demand (e.g., highest demand occurring in the billing month regardless of when it occurs). AIU says the aggregate impact of the proposed on-peak demand method is slight: proposed billing demands are slightly lower than present billing demands, where present demands are based on a customer's maximum demand regardless of when it occurs during the billing month. AIU states that for AmerenIP, AmerenCIPS, and AmerenCILCO, proposed billing demands are 97.8%, 96.3%, and 94.2%, respectively, of present billing demands for DS-3. For DS-4, proposed billing demands are 98.2%, 96.7%, and 98.4% of present billing demands for AmerenIP, AmerenCIPS, and AmerenCILCO, respectively. AIU claims that if only the on-peak demand is used, and the floor amount of 50% of the customer's off-peak demand ignored, the impact would be very small. For AmerenIP, AmerenCIPS, and AmerenCILCO, AIU says the proposed billing demands would be 97.7%, 95.5%, and 92.6%, respectively, of present billing demands for DS-3. For DS-4, proposed billing demands would be 98.2%, 96.0%, and 98.2% of present billing demands for AmerenIP, AmerenCIPS, and AmerenCILCO, respectively.

AIU argues that changing to an on-peak demand method empowers rate limiter customers to shift demands to the off-peak period and thus reduce the demand charge component of their bills. AIU believes that retaining the rate limiter mitigates the price signal for customers subject to the rate limit to shift to the off-peak period. AIU states that while Staff is correct that there are potential benefits to both customers and AIU by encouraging customers to shift use toward the off-peak period, the change to billing demand will be most effective without a rate limiter in place.

AIU says the change to an on-peak demand method was actually advocated by IIEC in the previous delivery services cases and the Commission adopted IIEC's recommendation requiring AIU to provide data to allow a rate impact comparison between the existing methods and the on-peak method in the next delivery services case. AIU says that while it acknowledges the support Mr. Lazare and Mr. Adkisson provide for this change to an on-peak method, AIU believes this support undermines their position regarding the DS-4 rate limiter. AIU says a common theme in Staff's and the GFA's position is the perceived disproportionate impact that a segment of customers would face.

AIU indicates that GFA further argues for seasonal rate differentiation. Mr. Adkisson states there is not sufficient evidence for the Commission to determine the appropriateness of and level of a seasonal differential in delivery rates based on examining the 12 grain drying customers; however AIU believes this is only partially

accurate. AIU agrees with Mr. Adkisson that there is insufficient evidence to set the level of a seasonal differential in delivery rates; however, AIU claims there is sufficient evidence to suggest that a majority of the 12 DS-4 grain-drying customers should pay a premium for primary voltage facilities. AIU says all DS-4 rate limiter grain drying customers are served from a primary supply line voltage (less than 15 kilovolt).

AIU states that all DS-4 customers have peak demands over 1,000 kW. According to AIU, these customers' demands are often large enough relative to all other customers on the circuit to drive the coincident peak to the fall grain drying season. AIU asserts that seasonal rate would not provide a lower price for these customers. AIU says an examination of circuits serving smaller (DS-3) customers eligible for the rate limiter has not yet been conducted. Until such analysis has been conducted, AIU claims it is unknown if demands contributed by DS-3 grain drying customers cause the circuit to peak in the fall. As a result, AIU suggests increasing the DS-3 rate limiter by an amount equal to the class average rate increase. AIU believes, however, that there is sufficient evidence in the record that the rate limiter affording to certain DS-4 customers should be eliminated.

AIU states that the Distribution Delivery Charge is based on a monthly demand and if a customer does not establish a demand during the monthly billing period, it will not pay a Distribution Delivery Charge in the month. AIU adds most grain drying customers set relatively large demands in 2 or 3 fall billing periods, and small demands in the remaining 9 or 10 billing periods. Thus, AIU says these grain drying DS-4 customers pay relatively small amounts of revenue in 9 or 10 billing periods and larger amounts in 2 or 3 monthly billing periods. According to AIU, most other DS-4 customers have relatively consistent usage, and thus a consistent revenue pattern, throughout the year.

AIU states that of the 12 grain drying rate limiter customers considered in this proceeding, 8 are served from a circuit and/or substation transformer with a fall peak, 2 customers are served from circuits and/or substation transformers that show equivalent peaks in both the summer and the fall, and 2 customers are served from the same substation with a peak occurring in the summer. AIU contends that customers or groups of customers contributing to the peak placed on distribution facilities, such as many of these grain dryers, should pay more of the cost for the system.

According to AIU, a review of the circuits serving DS-4 grain drying customers eligible for the rate limiter shows that the peak for those circuits is driven predominantly by customer demands occurring in the fall. In AIU's view, the rate limiter provides a subsidy to these seasonal customers at the expense of other DS-4 customers. AIU states that, assuming a DS-4 limiter of 2.82¢/kWh, 2.31¢/kWh, and 2.17¢/kWh, for AmerenIP, AmerenCIPS, and AmerenCILCO, respectively, grain drying customers would experience a benefit equivalent to just under 0.45¢/kWh. AIU adds that, assuming an average price per kWh paid of 9¢/kWh, the rate limiter would reduce the overall energy costs for a grain drying customer by about 5%.

AIU contends that DS-4 rate limiter customers drive the peak and costs on most distribution circuits, yet pay a relatively small amount toward those costs compared to non-grain drying customers. If the Commission finds the DS-4 limiter is still appropriate, but would like to begin the process of reducing reliance on the subsidy and set the rate at 3¢/kWh as AIU originally proposed for DS-3, AIU claims rate limitation reductions to class revenue would need to be reflected in AIU's proposed jurisdictional operating revenue. AIU says these values are provided in the third table on Ameren Ex. 26.1. AIU indicates that if the Commission instead chooses to simply increase the existing 2¢/kWh rate limiter by the average DS-4 rate increase for each AIU, the corresponding limited revenue amount are also shown within the third table of Ameren Ex. 26.1.

b. GFA's Position

GFA claims that its members suffered rate shock when the rates imposed in 2006 were implemented. Commission approval of the DS-3 and DS-4 rate limiters, however, helped to mitigate the impact of triple digit percentage rate increases for grain dryers and seasonal use customers. GFA says that customers that limit their total kWh usage during the four summer billing periods of June through September to 20% or less of their annual kWh consumption qualify and may be eligible for the rate limiter. The rate limiter is calculated each billing period for qualifying customers by adding the individual customer's monthly Distribution Delivery Charge and Transformation Charge revenues and dividing the sum by the customer's total kWh for that billing period. GFA states that if the combined charge is greater than 2¢/kWh, a credit for the amount over 2¢/kWh will be applied to the customer's bill. GFA indicates that the rate limiter limits the average monthly cost of the Distribution Delivery Charge and the Transformation Charge to 2¢/kWh, which is several times higher than the previous and current class average ¢/kWh, but can be less than what an individual customer would have otherwise paid. GFA notes that the rate limiter is not applicable to Customer, Meter, Transmission, Reactive or Power and Energy charges.

GFA indicates that the DS-3 and DS-4 tariffs with the rate limiter became effective October 19, 2007 and less than three weeks later, on November 2, 2007, AIU filed these rate cases. GFA says that AIU proposes to totally eliminate the DS-4 rate limiter, which would allow an unlimited increase for DS-4 customers and initially proposed a 50% increase to the DS-3 rate limiter, from 2¢/kWh to 3¢/kWh. GFA states that in its rebuttal testimony, AIU agrees to support an increase to the DS-3 rate limiter equal to the class average increase. For the purpose of this rate case, GFA indicates it will no longer object to such an increase; however, GFA continues to oppose the proposal to eliminate the DS-4 rate limiter. In GFA's view, it is simply too soon to eliminate the rate limiter.

GFA states that AIU has recommended across-the-board increases on its rates, with the exception of the rate limiter. GFA contends that AIU's proposal is unfair and would effectively undo the Commission's Order in Docket No. 07-0165. According to GFA, if the Commission raises AIU's rates across the board, then the rate limiter should receive that same treatment.

GFA says that if, in the next rate case, AIU bases its proposed rates on a class COSS, then the Commission will have the opportunity to review and reconsider all aspects of rate design, including the rate limiters. Additionally, GFA suggests that all parties will be able to voice their respective concerns and opinions regarding the rate limiters, seasonal rates, and other rate design features. GFA asserts that if the rate limiter is to be modified or eliminated, it should be done in conjunction with a COSS, where all factors can be considered.

In its Reply Brief, GFA says it has not ignored the Commission's direction in Docket No. 07-0165, and says it has performed the evaluation requested by the Commission. GFA claims that for a number of reasons, it and Staff determined that the most reasonable course of action is for the Commission to apply to the rate limiter the same across-the-board increases that are being applied to other rate components. While the Commission stated its desire to have the parties reevaluate the rate limiter, GFA argues there is nothing in its Order indicating its knowledge that AIU would file a rate case less than three weeks after implementation of the rate limiter, seeking to eliminate the rate limiter. GFA also says nothing in the Order indicates that the Commission anticipated an across-the-board increase rather than a full review of a class COSS and cost-based rate design.

AIU argues that its proposal to move to an on-peak determinant for establishing demand rates obviates the need for the rate limiter. GFA states that even if DS-4 customers were able to shift on-peak load to off-peak period and totally capture the prospective benefits of the proposed change in billing demand determination, the resulting benefits pale in comparison to the triple digit increases grain dryers will experience without the DS-4 rate limiter.

GFA proposes seasonal delivery rates while AIU argues against seasonal rates. According to GFA, AIU ultimately, takes the position that a proposal to implement seasonal delivery rates is not appropriate at this time and requires further analysis. GFA agrees that further analysis should take place, therefore, it recommends that the Commission order AIU to begin collecting data necessary for determining seasonal delivery rates and to provide those data to the Commission and other parties prior to filing its next electric rate case.

c. Staff's Position

Staff says that while AIU generally accepts the across-the-board approach to increasing existing rates, AIU continues to recommend that the rate limiter for the DS-4 class be eliminated. AIU argues that the peak for these customers is driven by demands during the fall season which suggests that customers under the rate limiter are being subsidized by others within the class. AIU also suggests the limiter would not have a significant effect on grain drying customers, reducing their overall energy costs by about 5%. AIU also presents the option of setting the limiter for DS-4 customers at 3¢/kWh as it originally proposed for DS-3.

Staff says that since it and AIU agree that bill impacts are the preeminent concern, it does not make sense to base rates for the large majority of customers on bill impacts while setting rates for a small number of customers receiving the rate limiter according to costs. Staff asserts that those latter customers can rightly complain of being held to one standard for ratemaking when other customers are held to another standard. In Staff's view, the only reasonable approach in this difficult ratemaking environment is to apply a consistent across-the-board approach to all existing rate elements, including the existing rate limiters for the DS-3 and DS-4 classes.

d. IIEC's Position

IIEC takes no position on the extension of the rate limiter for DS-3 customers; however, it opposes the extension for DS-4 customers. IIEC states that grain dryers and seasonal use customers are not the only customer classes that experienced large increases in delivery service rates. According to IIEC, some DS-4 customers other than grain dryers or seasonal use customers experienced rate increases of over 200% in AIU's last delivery service case. IIEC says other customer classes also experienced significant rate increases in going from the 2006 rates to the 2007 rates. In IIEC's view, there is no basis for a continued distinction between these customers and the customer group represented by GFA, especially where it establishes a continuing subsidy. IIEC asserts that GFA has not demonstrated why these particular DS-4 customers should be entitled to the continuing benefits of the rate limiter while other DS-4 customers do not enjoy rate mitigation.

GFA argues that the rate limiter has not been in effect long enough and points out that AIU filed this rate case three weeks after the rate limiter took effect. According to IIEC, GFA ignores the fact that the rate limiter for DS-4 grain drying customers will have been in place for almost one year by the time the rates approved in this case take effect. IIEC believes that under such circumstances, there is no justification for continuation of the rate limiter for DS-4 grain drying customers. In response to GFA's suggestion that the rate limiter should only be eliminated in conjunction with a COSS, IIEC points out that a COSS is available in this proceeding.

IIEC notes that Staff has concluded that elimination of the rate limiter would result in grain drying customers, such as the DS-4 grain drying customers, being held to one standard for ratemaking when other customers are held to another standard. IIEC argues that Staff has it exactly backwards. According to IIEC, the rate limiter for DS-4 customers, who happen to be grain dryers, does result in one standard being applied to those customers while another standard is applied to other DS-4 customers who have also experienced rate shock, but who do not benefit from the rate limiter.

e. Commercial Group's Position

According to the Commercial Group, given that the rate limiter subsidies must be collected only from DS-3 and DS-4 customers, phasing out the rate limiter would relieve

the stresses on the DS-3 and DS-4 customers who are required to provide both intra-class subsidies to the customers taking advantage of the rate limiter and interclass subsidies to other classes. The Commercial Group believes this is an unfair burden that should be eliminated.

The Commercial Group disagrees with Staff that elimination of the rate limiter is inconsistent ratemaking that singles out one group of customers for unequal treatment. The Commercial Group argues that eliminating a rate provision that created intra-class subsidies does not result in unequal treatment. In the Commercial Group's view, it puts all customers within that rate class on a more equal footing with respect to their rates being based on the true cost to serve. The Commercial Group insists that it is unequal for certain customers in a class to subsidize other customers in the class, particularly where the subsidized customers' rates are already below cost before the rate limiter is applied. The Commercial Group believes the rate limiter has served its limited transitional purpose and should be eliminated. If it is not completely eliminated in this case, the Commercial Group submits that the rate limiter should be phased out and eliminated as AIU proposed in its direct testimony.

The Commercial Group agrees with AIU and IIEC that the DS-4 rate limiter should be eliminated. The Commercial Group also urges the Commission to eliminate the DS-3 rate limiter. According to the Commercial Group, there is even more reason to do so, because DS-3 rates for AIU are already significantly above cost. The Commercial Group submits that with the rates of grain customers being below cost even before the rate limiter is applied, the rest of the DS-3 class is subsidizing not only other rate classes, but other ratepayers within the class. The Commercial Group claims that this double subsidy stresses DS-3 customers who are concerned with the impact of increasing electric bills on operations at schools, retail facilities, and industrial facilities.

f. Commission Conclusion

AIU proposes that the rate limiter provision for DS-3 be increased proportionate to the average rate-increase for that class, and that the provision for DS-4 be eliminated. AIU says that in Docket No. 07-0165, the Commission ordered that the rate limiter should be in place only as long as necessary. AIU also proposes moving to an on-peak determinate for establishing demand rates and claims there is no opposition to this proposal. AIU believes eliminating the DS-4 Rate Limiter would inject fairness by moving rates closer to cost and avoiding the unnecessary subsidization inherent in such limiters. AIU adds that customers who do not benefit from the rate limiter subsidize customers who receive a benefit.

For purposes of this proceeding, GFA does not oppose an increase to the DS-3 rate limiter equal to the class average increase. GFA continues to oppose the proposal to eliminate the DS-4 rate limiter because it believes it is too soon to eliminate that benefit. In Staff's view, the only reasonable approach is to apply a consistent across-the-board approach to all existing rate elements, including the existing rate limiters for the DS-3 and DS-4 classes. IIEC takes no position on the extension of the limiter in this

case for DS-3 customers; however, IIEC opposes the extension of the rate limiter for DS-4 customers. The Commercial Group advocates eliminating the rate limiter for both DS-3 and DS-4 classes.

As the parties are well aware, the Commission generally favors rates that reflect the cost of service. The Commission, however, is keenly aware that its rate decisions can have adverse impacts on some customers if extreme care is not exercised. The Commission is especially intent on avoiding the type of situation that led to the recent AIU rate redesign proceeding, Docket No. 07-0165. Given the circumstances and facts present here, the Commission believes that the best outcome will result if Staff's proposal to apply an across-the-board increase to the existing rate limiters for both DS-3 and DS-4 classes is adopted. The Commission 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.

2. Street Lighting

a. AIU's Position

AIU states that it and LGI concur on certain municipal street-lighting issues. AIU says it provided a detailed COSS, contained in Schedule E-6, for the current rate cases and will provide a similar COSS in the next set of rate cases, along with the requested lighting rate design study aimed at determining cost-based lighting fixture charges. With regard to LGI's street light fixture rate proposal, AIU disagrees with LGI's proposed approach.

For the purpose of this case, LGI recommends capping AmerenIP street light fixture rates, and that the resulting reductions to AmerenIP's filed revenue requirement related to street lighting be passed along to all delivery service customer classes. AIU notes that LGI only represents municipalities within the AmerenIP service territory.

AIU provides the following tables to demonstrate the street lighting proposals advanced by the AIU and LGI:

Average Cost per Month per Fixture

		AIU Proposal		LGI Proposal	
Municipality	Existing Rates	Monthly Price	Change	Incremental Change	Monthly Price
Champaign	$ 8.66	$ 12.64	$ 3.98	$ 1.29	$ 9.95
Bloomington	$ 8.03	$ 11.72	$ 3.69	$ 1.20	$ 9.23
Normal	$ 8.07	$ 11.78	$ 3.71	$ 1.20	$ 9.27
Urbana	$ 8.50	$ 12.33	$ 3.83	$ 1.17	$ 9.67
Decatur	$ 7.81	$ 11.40	$ 3.59	$ 1.16	$ 8.97

Per Capita Average Cost per Month

		AIU Proposal		LGI Proposal	
Municipality	Existing Rates	Monthly Price	Change	Incremental Change	Monthly Price
Champaign	$ 0.17	$ 0.24	$ 0.07	$ 0.02	$0.19
Bloomington	$ 0.49	$ 0.71	$ 0.22	$ 0.07	$0.56
Normal	$ 0.36	$ 0.52	$ 0.16	$ 0.05	$0.41
Urbana	$ -	$ -	$ -	$ -	$ -
Decatur	$ 0.86	$ 1.26	$ 0.40	$ 0.13	$0.99

According to AIU, LGI witness Hughes proposes to cap the fixture rates increase in the AmerenIP service territory by no higher than 14.89%. AIU states that the proposed DS-5 class provides customers with dusk-to-dawn photo cell-controlled lighting service. AIU adds that while it will typically own and maintain the lighting fixture, DS-5 will provide for customers who own their own lighting facilities as well.

AIU indicates that LGI only addresses the charges for fixtures. AIU indicates that the fixture charges in DS-5 do not cover power and energy charges, transmission charges, or delivery-service charges. To achieve the targeted revenue requirement for each class, AIU proposed fixture charges laid out in Ameren Ex. 12.7E. AIU proposes to adjust those charges on an equal percentage basis unique to each utility. AIU states that transmission and energy charges are charged separately through Rider TS and Rider BGS, and distribution delivery charges are assessed through a separate component within DS-5.

According to AIU, Ms. Hughes proposes that AmerenIP's fixture charges be capped based on the incremental costs of fixtures calculated several years ago for use in Docket Nos. 06-0070/06-0071/06-0072 (Cons.) and recommends funding this cap by shifting costs to other rate classes. In AIU's view, Ms. Hughes' case for carving out an exception to the across-the-board increase is not persuasive. AIU complains that Ms. Hughes does not clarify why AIU's DS-5 class, and that class alone, should be allowed use of a non-across-the-board revenue allocation method, while other classes are held to an across-the-board approach. AIU also says that Ms. Hughes fails to extend the concept of incremental-cost pricing to AmerenCIPS and AmerenCILCO. AIU argues that LGI customers have the option of choosing to purchase their own street lighting fixture and avoid AmerenIP’s fixture rates all together, while other delivery service customers have no service choice. AIU insists that it is unfair to shift an amount potentially in excess of $5 million dollars from charges that certain customers pay by choice to other customers, including residential customers.

In its Reply Brief, AIU says it does not think it is appropriate to shift revenues between classes in a manner that would disturb the intended purpose of the rate redesign docket. In particular, AIU claims it would not be appropriate to shift revenue recovery between classes in a manner that creates impacts for residential and small business customers. AIU argues that the revenue impacts associated with a

realignment of rates to more closely match class cost of service indicators would result in impacts to residential customers. AIU objects to such a realignment of rates at this time.

AIU acknowledges the disparity between street light fixture rates in each service territory; however, AIU says it is unclear what authority or legal basis the Commission would have to shift revenue responsibility between separate legal entities. AIU says that while the rate proceedings in this matter are consolidated, the operating utility entities that make up AIU are not. AIU argues that in future rate proceedings, the more appropriate approach to bring uniformity would likely be a rate design that moves rates toward class cost of service indicators, to the extent feasible.

b. LGI's Position

LGI claims that the street lighting fixture charge is unique in this docket because it is not a delivery service; rather it is a payment for a tangible piece of hardware and the labor involved in maintaining that hardware. LGI indicates that the delivery service charge for street lights is totally separate and apart from the street light fixture. LGI says in an over-simplified example, the fixture charge covers the cost of the arm and bulb and how many persons it takes to change the light bulb on the street light. According to LGI, because of its unique nature, there is no reason why the Commission can not separately set the rate for the street lighting fixture charge based on the cost of service as AIU did for the meter and customer charge, rather than on an across-the-board basis.

LGI states that the fixture charges vary greatly for the three electric utilities. Initially, LGI proposed that the Commission unify the fixture charges in this proceeding. LGI believes that the move to common lighting offerings across the footprint is a step toward easing customer understanding of AIU lighting offerings and streamlining operations. LGI says this standardization already occurred for Meter and Customer Charges, which are now all identical for the three utilities. LGI argues that the result of applying the across-the-board increase to street light fixtures would be to move the fixture charges further apart, making a standardized offering more difficult in the future.

LGI contends that it takes the same number of persons to change a light bulb for AmerenIP as it does for AmerenCILCO and AmerenCIPS; yet, using an across-the-board increase, the rates charged for street lighting fixtures will increase by 9.5% for AmerenCILCO, 19.2% for AmerenCIPS, and 46.0% for AmerenIP. LGI states that for AmerenCIPS the current street light fixture charge for a 100-Watt light fixture is $3.12 per month, for AmerenCILCO the charge is $7.13, and for AmerenIP, the charge is $7.59. LGI says under AIU's proposed across-the-board increase, these rates would increase to $3.72 for AmerenCIPS, $7.81 for AmerenCILCO, and $11.08 for AmerenIP. LGI suggests the cost of a light bulb and the cost to replace the light bulb is not nearly three times the amount for AmerenIP compared to AmerenCIPS.

LGI believes that eventually the street light fixture charge should be uniform throughout AIU's service areas; however, in its rebuttal testimony LGI focuses only on AmerenIP. Using AmerenIP's 2006 embedded COSS and the lighting specific incremental cost study performed in the last case, Ms. Hughes recommends that the increase to AmerenIP's lighting fixture rates be limited so that the fixture rates are set equal to the common incremental cost for each fixture type and size. LGI says using the incremental cost, the AmerenIP fixture charges still will be higher than the cost for AmerenCIPS and AmerenCILCO. For example, LGI indicates that the incremental cost for a 100 watt high pressure sodium vapor fixture for AmerenIP is $8.72, while the proposed rate for the same fixture for AmerenCIPS is $3.72 and for AmerenCILCO is $7.81. LGI states that under its current proposal, AmerenIP customers would still pay more for fixture charges than municipalities taking service from either AmerenCIPS or AmerenCILCO but the disparity would be lower than if the fixture charges were increased using AIU's proposed across the board increase. LGI proposes that the Class B pole charge also be set equal to the incremental cost for AmerenIP. Under LGI's proposal, the revenue reduction resulting from the decrease in fixture and pole charges from the proposal by AmerenIP would be allocated to the other DS customer classes using an equal percentage increase in the DS delivery charge.

LGI claims the result of its proposal is that the street lighting fixture charge for AmerenIP customers would increase by 14.89%. LGI says the effect on other customers would increase the across-the-board increase for the DS-1 through DS-4 delivery service charge from 41.14% to 42.58%. Under LGI's proposal, the DS-5 delivery service charge rate also would increase by the same percentage (42.58%). LGI states that taking into account both the recommended fixture charge and the increase to the DS-5 delivery charge, the overall increase to the DS-5 Lighting Class is 21.37%.

LGI argues that this total lower percentage increase for the DS-5 lighting class is supported by AIU's own embedded COSS. LGI claims this study indicates that the DS-5 Lighting Class contributes a higher return on rate base at existing rates than all other DS rate classes, except for the DS-2 class. LGI asserts that applying an equal across-the-board percentage increase to all rate classes maintains or amplifies the existing disparity that DS-5 lighting rates will continue contributing higher returns relative to other rate classes.

According to LGI, AIU's opposition appears to be rooted in the fact that since it is recommending an across-the-board increase for all other classes, it believes that there should be no exception for the fixture charge. In LGI's view, AIU misses the point that the fixture charge is not a traditional delivery service charge. LGI says the delivery service charge portion of the DS-5 rate remains subject to the across-the-board increase. LGI recommends that only the light bulb, fixtures, and light bulb changing be separated from the across-the-board increase as was done with the Meter and Customer Charges that are now uniform for AmerenCILCO, AmerenCIPS, and AmerenIP.

LGI says it made three additional recommendations, all of which were accepted by AIU. LGI recommends that AIU be required to file a detailed COSS in its next rate case showing the allocation of costs between the delivery service customer classes, including a company-wide lighting cost of service analysis for AIU to identify lighting fixture costs. LGI recommends that AIU be required to file a detailed streetlight rate design study to determine cost-based lighting fixture charges. LGI recommends that any reductions to AIU's filed revenue requirement resulting from the Commission's decision should be passed along to all DS customer classes, including the DS-5 Lighting Class, in the form of a lower across-the-board percentage rate increase. LGI suggests that these recommendations should be included in the final order in this proceeding.

According to LGI, AIU attempts to confuse the issue by showing the per capita average cost per month for the fixture charge. LGI claims this is a meaningless comparison because rates are not set on a per capita basis. LGI says AIU simply takes the monthly charge for municipal lighting fixtures by municipality divided by the population of the municipality. LGI complains that AIU does not explain why this is a meaningful exercise and, if it is so meaningful, why it does not determine all of its rates on a per capita basis. LGI asserts that AIU can not hide the fact that if an across-the-board increase is granted for AmerenIP's municipal lighting fixture charge, the charge will be $11.08 compared with only $3.72 for AmerenCIPS and $7.81 for Ameren CILCO.

In response to AIU's statement that LGI customers can avoid the charge by buying their own arms and bulbs if they do not like the rate, LGI claims AIU apparently wants to make the fixture charge so unreasonable that municipalities will install their own arms and bulbs rather than pay for AmerenIP's. LGI argues that while taking down AmerenIP's arms and bulbs and replacing them with municipality-owned arms and bulbs may be a long-term solution, changing out all arms and bulbs on street lights is neither an immediate nor a practical solution. Instead, LGI contends the reasonable and practical solution is for the Commission to set the municipal street lighting fixture charge based on the incremental cost.

c. Commission Conclusion

AIU proposes to increase street lighting rates, including its charges for fixtures, on an across-the-board basis. LGI objects to increasing fixture charges in AmerenIP's service area in the manner AIU proposes. LGI recommends that the Commission limit fixture charges to the incremental cost of those fixtures. AIU does not believe there is sufficient reason to deviate from its across-the-board rate increase proposal for light fixture charges. Also, AIU expresses concern about shifting revenue recovery between classes in a manner that creates impacts for residential and small business customers.

It appears to the Commission that LGI has raised a legitimate concern. In the Commission's view, ultimately, it will in all likelihood be difficult for AIU to justify light fixture charges that are as different as they currently are between AmerenCILCO, AmerenCIPS, and AmerenIP. But as previously discussed, the Commission is aware

that its rate decisions can have adverse impact on some customers if extreme care is not exercised. The Commission wishes to avoid the type of situation that led to the recent AIU rate redesign proceeding, Docket No. 07-0165. Given the circumstances and facts present here, the Commission believes that the best outcome will result if it adopts AIU's proposal to increase light fixture charges on an across-the-board basis. The Commission directs AIU, in its next electric rate case to address the possibility of moving the light fixture charges toward a more similar charge among AmerenCILCO, AmerenCIPS, and AmerenIP.

3. Allocation of Costs to Subclasses

As discussed elsewhere in this Order, the Commercial Group opposes using an across-the-board approach to increase electric rates, favoring the use of AIU's COSS as the basis for any increase. In the event the Commission accepts the Commercial Group's recommendation on this point, the Commercial Group is concerned about the application to subclasses.

The Commercial Group argues that with respect to the DS-3 and DS-4 subclasses, the COSS do not accurately match cost to revenues on the subclass level and therefore are not reliable for differentiating subclass revenue levels. The Commercial Group states that the AmerenCILCO cost study shows the DS-4 secondary subclass as requiring a 3,729% increase. The Commercial Group claims that AIU assigned 100% of line transformer cost ($15.1 million) for the DS-4 class to the DS-4 secondary subclass but, none of the corresponding $2.6 million in transformation revenues that AIU received from the class. The Commercial Groups says that instead, only $53,000 in revenue, consisting entirely of meter charge and customer charge revenue was allocated to DS-4 secondary. The Commercial Group contends that given that transformer cost but not the revenue produced from those transformers was allocated to DS-4 secondary, it is not surprising that the study would show that an enormous revenue increase would apparently be required for the DS-4 secondary. The Commercial Group concludes that AIU's COSS are generally reliable for class costs and revenues, but are not reliable at the subclass level.

While the Commission appreciates the Commercial Group's concern regarding the allocation of costs and revenue to DS-4 subclasses, as the Commission has chosen to not use AIU's COSS as the basis for setting rates in this proceeding, it does not appear that this issue need be addressed further in this Order.

4. Combining DS-3 and DS-4

a. Kroger's Position

Kroger states that the DS-3 rate class is comprised of nonresidential customers that have billing demands ranging from 150 kW up to 1,000 kW, while the DS-4 rate class is comprised of all nonresidential customers with billing demands of 1,000 kW or greater. Kroger adds that the Distribution Delivery Charge is a demand charge levied

on a per-kW basis, with rates differentiated with respect to voltage level: primary, high voltage, and transmission voltage. Kroger says unlike other charges contained within the DS-3 and DS-4 rates, the Distribution Delivery Charge is not uniform between DS-3 and DS-4. According to Kroger, for each AIU utility, and at each voltage level, the proposed Distribution Delivery Charge is significantly higher for DS-3 than DS-4. Kroger proposes that the Distribution Delivery Charge for customers on the DS-3 and DS-4 rate schedules should be approximately equalized. Kroger argues that there is no significant cost of service difference between DS-3 and DS-4 customers at the same voltage level, yet AIU proposes that DS-3 customers pay a substantially higher Distribution Delivery Charge.

Kroger suggests that if providing a kW of service to customers at a given voltage level costs the same whether the customer requires 150 kW or 2,000 kW, then perhaps these customers should not be placed into different rate classes in the first instance. Kroger also claims it is not reasonable to charge the 150 kW customer a dramatically higher per-kW Distribution Delivery Charge than the 2,000 kW customer taking service at the same voltage. In Kroger's view, the lack of a uniform Distribution Delivery Charge for DS-3 and DS-4 will result in an anomalous rate transition that will cause a great inequity. Kroger asserts for example, if there are two AmerenCILCO primary voltage customers who are otherwise identical, but one places a 1,000 kW demand on the system (DS-4) and the other places a 600 kW demand on the system (DS-3), the 600 kW customer that places a significantly smaller strain on the system will pay a higher Distribution Delivery total bill than the 1,000 kW customer. Kroger suggests that AIU's proposed Distribution Delivery Charges would send the signal to DS-4 customers to not reduce energy consumption. Kroger believes this anomaly is particularly inappropriate given the Commission's interest in promoting energy efficiency.

Kroger complains that AIU ignored the Commission's Order in the previous rate case, and failed to address the issue of whether there is sufficient justification for separate DS-3 and DS-4 classes in this proceeding. Instead, Kroger says AIU has proposed an equal percent across-the-board delivery rate increase, which retains the relative disparities between DS-3 and DS-4 established in the last proceeding, and makes the absolute differences between the rate schedules even greater. Kroger asserts that the Commission ordered AIU in its previous distribution rate case filing (Docket Nos. 06-0070, 06-0071, and 06-0072 (Cons.)) to "address [the appropriateness of maintaining separate DS-3 and DS-4 rates] in its next delivery services rate case filing." (Order at 175)

According to Kroger, AIU's COSS in this proceeding provide even more evidence that DS-3 and DS-4 rates should be converged. Using the information from AIU's Schedule E-6 filings, Kroger prepared the table below comparing the rates of return being provided by DS-3 and DS-4 customers.

AIU COSS Rates of Return

Utility Distribution Company	Ill. Elec.	Rates of Return DS-3a	DS-3b	DS-4
AmerenIP	2.75%	3.40%	5.94%	4.44%
AmerenCIPS	4.72%	9.93%	8.83%	2.77%
Ameren CILCO	6.92%	12.22%	12.89%	5.31%

Kroger says AIU is generally over-recovering costs from DS-3 customers relative to DS-4. In Kroger's view, these results are not surprising in light of the disparity in the Distribution Delivery Charges between the two customer classes. Kroger asserts that the greater the disparity in the Distribution Delivery Charges, the greater the disparity in rates of return being produced by the two customer classes.

Kroger believes the artificial distinction between DS-3 and DS-4 customers should be eliminated in this proceeding and the DS-3 and DS-4 rates should be jointly determined. Kroger calculated uniform distribution delivery charges for DS-3 and DS-4, which it presented in Kroger Ex. 1.1 using AIU's requested revenue requirement. Kroger states that the only difference between the DS-3 and DS-4 Distribution Delivery Charges is the recognition of DS-4 reactive power revenues as a credit against the DS-4 Distribution Delivery Charge. If the Commission finds merit in this argument, but is reluctant to move to uniform DS-3 and DS-4 rates at this time, Kroger suggests that, in the alternative, the Commission initiate steps in this proceeding to move the DS-3 and DS-4 rate schedules closer together over time. Kroger suggests that this could be implemented by removing 50% of the differential between the rates at this time.

b. AIU's Position

Kroger argues that the DS-3 and DS-4 rate schedules should be approximately equalized, that is, there should be no cost of service difference between customers who are served at the same voltage level. According to AIU, Kroger claims that the issue of the relationship between the DS-3 and DS-4 rates was required to be addressed by AIU in this proceeding. AIU observes that no other party has made this claim. AIU says the Commission's Order states: "When Ameren files its next delivery services rate case (assuming that filing is in 2009 or later), it should provide sufficient information for the Commission to either retain the current DS-3 classification or adopt the DS-3 classification within the subclasses proposed by Wal-Mart." (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 156) AIU claims Kroger knew or should have known upon review of the direct filing, that the DS-3 and DS-4 rate consolidation analysis had not been performed.

In AIU's view, the Commission's decision to wait until 2009 to review this issue makes sense. AIU notes that these delivery service rates first came into effect on January 2, 2007 and AIU believes waiting for some period of time is appropriate, so that any analysis offered post-2009 would have sufficient data and information. AIU alleges

that combining rates without the required analysis is a recipe for disaster. AIU contends that undue bill impacts, questionable price signals and revenue recovery concerns all remain unknown and unpredictable. AIU says the Distribution Delivery Charge recovers the remainder of the revenue requirement, and is currently set to recover the revenue requirement from DS-3 and DS-4 classes. AIU asserts that combining these rates at this time leaves too many unknowns, and is inappropriate at this time. AIU submits that further analysis of the DS-3 and DS-4 classes could lead to more rate differentiation rather than less.

c. IIEC's Position

IIEC suggests that in lieu of adopting Kroger's proposal to equalize distribution delivery service charges for DS-3 and DS-4, the Commission adopt a cost-based approach to revenue requirement allocation, which would lead to lower distribution and delivery service charges for DS-3 customers as well as DS-4 customers. IIEC generally agrees with the AIU position that DS-3 and DS-4 should not be equalized in this case, because there has not been sufficient cost analysis provided to justify the combination. Such a combination would result in lower charges for DS-3 customers and higher charge for DS-4 customers, according to IIEC. IIEC notes that Kroger's proposal is based on statements from prior delivery service rate cases that, on a conceptual basis, suggest the cost per kW of serving a customer of the same voltage level at 900 kW is not much different than the cost per kW of serving a similar customer at 1,100 kW of demand. IIEC observes that AIU witnesses point out that the cost of serving these customers may be similar, but the revenue from the customers may or may not be sufficient to recover their individual costs. According to IIEC, this suggests that rate changes not discussed in this record may be needed to implement the Kroger approach. IIEC also argues that the Commission directed that this issue be considered in a rate case filing in 2009 or later citing to Docket Nos. 06-0070, 07-0071, and 06-0072 (Cons.) (Order at 156).

IIEC argues further that Kroger's alternative proposal to equalize delivery distribution charges for DS-3 and DS-4 by removing 50% of any difference between the rates as they exist today does not mitigate AIU's concerns in terms of potential impacts and consequences of equalizing these rates at this time. Adoption of the AIU proposal would not, according to IIEC, reduce by 50% the magnitude of the problems associated with the Kroger proposal. IIEC adds that the impacts of moving towards equalization remain unknown and unpredictable based on the record in this case. IIEC, therefore, recommends that the proposal to combine DS-3 and DS-4 be rejected in this case.

d. Commission Conclusion

In AIU's last rate case, the Commission entertained not only arguments over the possibility of combing rates DS-3 and DS-4, but also the possibility of splitting rate DS-3 into subclasses. The Order in AIU's last rate case clearly contemplated reconsidering whether to split rate DS-3 into subclasses in 2009 or after. While the Order was not quite as clear with respect to when it would reconsider combining rates DS-3 and DS-4,

the Commission does not believe combining rates DS-3 and DS-4 in this rate case and, possibly creating a new rate DS-3 in a subsequent rate case constitutes sound ratemaking policy. In fact, it seems to contradict the rate design principle commonly called rate continuity. Thus, while the Commission 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.

X. FINDINGS AND ORDERING PARAGRAPHS

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

(1) AmerenCILCO, AmerenCIPS, and AmerenIP are Illinois corporations engaged in the distribution and sale of electricity and natural gas to the public in Illinois, and are public utilities as defined in Section 3-105 of the Act;

(2) the Commission has jurisdiction over the parties hereto and the subject matter herein;

(3) the recitals of fact and conclusions of law reached in the prefatory portion of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law; Appendix A attached hereto provides supporting calculations for those portions of this Order concerning AmerenCILCO's electric operations; Appendix B attached hereto provides supporting calculations for those portions of this Order concerning AmerenCIPS' electric operations; Appendix C attached hereto provides supporting calculations for those portions of this Order concerning AmerenIP's electric operations; Appendix D attached hereto provides supporting calculations for those portions of this Order concerning AmerenCILCO's gas operations; Appendix E attached hereto provides supporting calculations for those portions of this Order concerning AmerenCIPS' gas operations; and Appendix F attached hereto provides supporting calculations for those portions of this Order concerning AmerenIP's gas operations;

(4) the test year for the determination of the rates herein found to be just and reasonable should be the 12 months ending December 31, 2006, as adjusted; such test year is appropriate for purposes of this proceeding;

(5) for purposes of this proceeding, the net original cost rate base for AmerenCILCO’s electric delivery service operations for the test year ending December 31, 2006, as adjusted, is $240,625,000;

(6) for purposes of this proceeding, the net original cost rate base for AmerenCIPS' electric delivery service operations for the test year ending December 31, 2006, as adjusted, is $443,743,000;

(7) for purposes of this proceeding, the net original cost rate base for AmerenIP's electric delivery service operations for the test year ending December 31, 2006, as adjusted, is $1,254,459,000;

(8) for purposes of this proceeding, the net original cost rate base for AmerenCILCO's gas delivery service operations for the test year ending December 31, 2006, as adjusted, is $183,734,000;

(9) for purposes of this proceeding, the net original cost rate base for AmerenCIPS' gas delivery service operations for the test year ending December 31, 2006, as adjusted, is $181,735,000;

(10) for purposes of this proceeding, the net original cost rate base for AmerenIP's gas delivery service operations for the test year ending December 31, 2006, as adjusted, is $518,857,000;

(11) a just and reasonable return which AmerenCILCO should be allowed to earn on its net original cost electric delivery service rate base is 8.01%; this rate of return incorporates a return on common equity of 10.65%;

(12) a just and reasonable return which AmerenCIPS should be allowed to earn on its net original cost electric delivery service rate base is 8.20%; this rate of return incorporates a return on common equity of 10.65%;

(13) a just and reasonable return which AmerenIP should be allowed to earn on its net original cost electric delivery service rate base is 8.68%; this rate of return incorporates a return on common equity of 10.65%;

(14) a just and reasonable return which AmerenCILCO should be allowed to earn on its net original cost gas delivery service rate base is 8.03%; this rate of return incorporates a return on common equity of 10.68%;

(15) a just and reasonable return which AmerenCIPS should be allowed to earn on its net original cost gas delivery service rate base is 8.22%; this rate of return incorporates a return on common equity of 10.68%;

(16) a just and reasonable return which AmerenIP should be allowed to earn on its net original cost gas delivery service rate base is 8.70%; this rate of return incorporates a return on common equity of 10.68%;

(17) the rate of return for AmerenCILCO set forth in Finding (11) results in base rate electric delivery service operating revenues of $115,827,000 and net

annual operating income of $19,273,000 based on the test year approved herein;

(18) the rate of return for AmerenCIPS set forth in Finding (12) results in base rate electric delivery service operating revenues of $218,466,000 and net annual operating income of $36,387,000 based on the test year approved herein;

(19) the rate of return for AmerenIP set forth in Finding (13) results in base rate electric delivery service operating revenues of $442,556,000 and net annual operating income of $108,887,000 based on the test year approved herein;

(20) the rate of return for AmerenCILCO set forth in Finding (14) results in base rate gas delivery service operating revenues of $71,308,000 and net annual operating income of $14,754,000 based on the test year approved herein;

(21) the rate of return for AmerenCIPS set forth in Finding (15) results in base rate gas delivery service operating revenues of $70,450,000 and net annual operating income of $14,938,000 based on the test year approved herein;

(22) the rate of return for AmerenIP set forth in Finding (16) results in base rate gas delivery service operating revenues of $167,424,000 and net annual operating income of $45,140,000 based on the test year approved herein;

(23) the electric delivery service rates as well as the gas delivery service rates of AmerenCIPS and AmerenIP which are presently in effect are insufficient to generate the operating income necessary to permit each company the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(24) the electric and gas delivery service rates of AmerenCILCO which are presently in effect are inappropriate and generate operating income in excess of the amount necessary to permit the company the opportunity to earn a fair and reasonable return on net original cost rate base: these rates should be permanently canceled and annulled;

(25) the specific rates proposed by AmerenCILCO, AmerenCIPS, and AmerenIP in its respective initial filings do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; the proposed rates of each company should be permanently canceled and annulled consistent with the findings herein;

(26) AmerenCILCO should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of $115,827,000, which represents a decrease of $2,778,000 or (2.25%); such revenues, in addition to other tariffed revenues, will provide AmerenCILCO with an opportunity to earn the rate of return set forth in Finding (11) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCILCO;

(27) AmerenCIPS should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of $218,466,000, which represents an increase of $21,956,000 or 10.31%; such revenues, in addition to other tariffed revenues, will provide AmerenCIPS with an opportunity to earn the rate of return set forth in Finding (12) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCIPS;

(28) AmerenIP should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of $442,556,000, which represents an increase of $103,867,000 or 29.16%; such revenues, in addition to other tariffed revenues, will provide AmerenIP with an opportunity to earn the rate of return set forth in Finding (13) above; based on the record in this proceeding, this return is fair and reasonable for AmerenIP;

(29) AmerenCILCO should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of $71,308,000, which represents a decrease of $9,234,000 or (11.19%); such revenues, in addition to other tariffed revenues, will provide AmerenCILCO with an opportunity to earn the rate of return set forth in Finding (14) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCILCO;

(30) AmerenCIPS should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of $70,450,000, which represents an increase of $7,659,000 or 11.74%; such revenues, in addition to other tariffed revenues, will provide AmerenCIPS with an opportunity to earn the rate of return set forth in Finding (15) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCIPS;

(31) AmerenIP should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of $167,424,000, which represents an increase of $39,792,000 or 30.01%; such revenues, in addition to other tariffed revenues, will provide AmerenIP with an opportunity to earn the rate of return set forth in Finding

(16) above; based on the record in this proceeding, this return is fair and reasonable for AmerenIP;

(32) determinations regarding cost of service, interclass revenue allocations, rate design, and tariff terms and conditions, as are contained in the prefatory portion of this Order, are reasonable for purposes of this proceeding; the tariffs filed by AmerenCILCO, AmerenCIPS, and AmerenIP should incorporate the rates and rate design set forth and referred to herein;

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

(34) all motions, petitions, objections, and other matters in this proceeding which remain unresolved should be disposed of consistent with the conclusions herein.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets at issue in these dockets and presently in effect for electric delivery service rendered by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP are hereby permanently canceled and annulled effective at such time as the new electric delivery service tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general increase in electric delivery service rates, filed by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP on November 2, 2007 are permanently canceled and annulled.

IT IS FURTHER ORDERED that the tariff sheets at issue in these dockets and presently in effect for gas delivery service rendered by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP are hereby permanently canceled and annulled effective at such time as the new gas delivery service tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general increase in gas delivery service rates, filed by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP on November 2, 2007, are permanently canceled and annulled.

IT IS FURTHER ORDERED that Central Illinois Light Company d/b/a AmerenCILCO is authorized to file new tariff sheets with supporting workpapers in

accordance with Findings (26), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Public Service Company d/b/a AmerenCIPS is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (27), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Illinois Power Company d/b/a AmerenIP is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (28), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Light Company d/b/a AmerenCILCO is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (29), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Public Service Company d/b/a AmerenCIPS is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (30), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Illinois Power Company d/b/a AmerenIP is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (31), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

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

By order of the Commission this 24th day of September, 2008.

(SIGNED) CHARLES E. BOX

Chairman