b. AIU Position

In defense of its use of the NCP methodology, AIU observes that the Commission approved of its use in allocating distribution plant costs in AIU's prior delivery services rate orders. Continued use of NCP is fitting, according to AIU, because it more appropriately allocates costs to customers that cause the costs to arise since, on-balance, NCP demands more closely match the demands placed on local substation and primary line facilities. AIU agrees with Staff that its facilities are built to serve demands based on locality and that geographical locations do encompass customers in multiple rate classes. The fault in Staff's position, in AIU's opinion, is that Staff does not consider the fact that customers within these geographical locations can peak at various times throughout the year.

AIU states that Staff's focus appears to be on the "multiple rate classes" element of CP demand, ignoring the fact that CP demand is always less than the sum of the localized demands placed on distribution facilities. AIU indicates that local facilities such as substations and primary lines are not built and sized with this level of diversity in mind. Instead, AIU explains that distribution system planners look at the expected peak of customers connected to the facilities, whether they occur in summer, fall, winter, or spring. This is based on the fact that the collective peaks on individual systems are greater than the CP. AIU maintains that the NCP demand more closely matches the load diversity on these more localized systems.

AIU states further that the use of CP demand would not be beneficial to many of its customers. According to AIU, the use of CP would increase costs to the DS-1, DS-3, and DS-4 rate classes but would lower costs to the DS-2 and DS-5 classes for AmerenIP. For AmerenCIPS, the DS-3 and DS-5 classes would be allocated lower costs under the CP allocation; however, the DS-1, DS-2, and DS-4 customers' costs would increase. The affects for AmerenCILCO are that the DS-1 and DS-5 rate classes receive less costs utilizing CP while DS-2, DS-3, and DS-4's costs would be higher.

The notion that DS-5 customers should not bear any costs for substations or primary lines, since they peak during off-peak, evening hours, is also problematic for AIU. AIU states that lighting customers use primary lines and substations and should be allocated at least some costs for the use of these assets. To allocate zero substation and primary line costs to the DS-5 class is flatly incorrect.

AIU disagrees that the use of NCP "punishes" non-weather-sensitive customers, as Staff contends. Instead, AIU contends that it appropriately allocates the cost of facilities to match how the facilities were designed, built, and sized. CP, on the other hand, is a detriment to these rate classes, according to AIU. AIU maintains that allocating substations and primary lines based on CP is improper because it would fail to appropriately align costs with the cost causers for which the systems are designed and constructed. AIU argues that the use of NCP provides the most accurate methodology for allocating distribution assets to ensure that no customer rate class subsidization occurs.

With regard to GFA's seasonal pricing concerns and the allocation of primary lines and substation costs, AIU continues to believe that such seasonal rates for the DS-2, DS-3, and DS-4 classes will ultimately create a subsidy by non-seasonal customers. AIU nevertheless does not object to examining a sample of circuits serving the DS-3 and DS-4 in order to bring clarity to the debate in the next rate case. AIU acknowledges that such a review may lead to improvements in its COSS.

c. IIEC Position

IIEC opposes Staff's recommendation that the CP allocator be used to allocate costs of primary distribution lines and substations. Contrary to Staff's suggestions, IIEC argues that the NCP method reflects the collective demands of every rate class and, in certain instances, reflects the collective demands of more rate classes than does the CP method. IIEC contends that this point is best illustrated by Staff's discussion of how the NCP method penalizes the lighting class. Staff's discussion ignores the fact that in the AIU COSS, the CP method does not recognize that the DS-5 rate class has any demand whatsoever and allocates no costs for primary lines and substations to the DS-5 class. IIEC states that it is obviously necessary to use primary lines and substations to serve the DS-5 class. IIEC avers that an allocation method that results in this class being assigned none of the cost of those facilities is clearly an erroneous method. The NCP method, on the other hand, does not suffer from this deficiency and recognizes the collective demand of every rate class regardless of when it occurs, according to IIEC.

d. GFA Position

GFA agrees with AIU that substations and distribution lines are designed to serve the maximum demand expected on the facilities regardless of the season. GFA, however, is still interested in the possibility of seasonal class distribution rates. GFA recognizes that grain companies can contribute to significant loads on substations and primary lines, particularly in the fall. Of concern to GFA, however, is the fact that AIU has provided no system-wide seasonal load data for primary lines and substations, the costs of which are being allocated to each of the DS-2, DS-3, and DS-4 customer classes from which grain companies are served, along with many other users. GFA understands that summer month coincident peaks are typically higher on the AIU system than are winter month coincident peaks. Because the coincidental system peaks on the AIU system vary by season, GFA opines that AIU's distribution system cost of service varies by season. This leads GFA to the conclusion that AIU should price its distribution delivery service charges, excluding monthly fixed charges, higher during the summer and lower during the non-summer months. GFA has not requested a special rate for grain dryers. Rather, it is requesting that AIU begin collecting the necessary data to conduct analysis of prospective seasonal cost based rates for DS-2, DS-3, and DS-4 customers with regard to costs of primary lines and substations. While AIU continues to disagree with GFA's conclusion regarding seasonal pricing, GFA states that AIU concedes that the information requested by GFA could lead to more proper cost allocation and pricing, and has agreed to perform further study and provide the result in the next rate case.

e. Commission Conclusion

As with any cost allocation issue, the Commission's goal is to allocate costs to those customers who cause the costs. In this instance, the Commission must determine which allocation method, NCP or CP, best allocates the costs of primary distribution lines and substations. When constructing or expanding primary lines and substations, a utility considers what load those customers to be served by the facilities will impose on the facilities. In most situations, the facilities will serve customers from more than one customer class. The peak of each individual class to be served by the facilities is irrelevant. What is relevant is the combined or coincident peak of all of those served by the facilities, regardless of which class each customer is in. The utility therefore sizes and constructs primary lines and substations to accommodate the anticipated coincident peak.

Why the allocation of the costs of primary lines and substations should be considered differently is unclear to the Commission. Consistent with cost-causation principles, those customers imposing a demand on the facilities at the time of the coincident peak (which was the primary driver in determining the facility size) should be allocated a proportionate share of the costs. The Commission recognizes that under this analysis, DS-5 lighting customers, because they tend to have zero demand during the coincident peak, are not allocated any of the costs of primary lines and substations. In other words, DS-5 customers are not responsible for any of peak demand on primary lines and substations. Because, however, DS-5 customers are rarely, if ever, considered in sizing primary lines and substations, this result is not inappropriate. This is not to suggest that DS-5 customers should not be expected to pay for distribution service. DS-5 customers' delivery service charges will consist of costs for facilities and services other than primary lines and substations. Because the demands of multiple classes on primary lines and substations more closely correspond to CP rather than NCP demands, the Commission agrees with Staff that the most reasonable, cost-based approach is to allocate the cost of this equipment according to the collective peak demands of all rate classes.

AIU's discussion of impacts on customers from using the CP allocator is misplaced. As Staff indicates, the underlying goal of any COSS is to allocate costs to those customers who cause the costs to be incurred. While rate impacts are of concern, the appropriate time to consider rate impacts is after costs have been allocated. At that time, rate mitigation efforts could be used to address any unreasonable or inappropriate rate impacts. In addition, that IIEC would oppose an allocator that shifts costs to larger customers comes as no surprise to the Commission. But given IIEC's concerns about assigning costs to cost-causers, the Commission finds IIEC's position on this issue somewhat inconsistent.

3. Allocation of Electric Distribution PURA Tax

Following the 1970 elimination of the Personal Property Tax, Illinois utilities became subject to a tax on invested capital, pursuant to the PURA. Prior to 1998 for electric utilities, the tax was assessed at a rate of 0.8% of the utility's invested capital. In conjunction with the electric restructuring legislation adopted in 1997, Illinois revised the PURA to impose a per kWh tax on electricity distribution by electric public utilities, rather than a tax on invested capital. AIU proposes that the electric distribution tax be allocated and collected from customers based on kWh sales as well. IIEC opposes that proposition and, instead, contends that the tax should be allocated on a demand basis, using the manner in which the tax was assessed and collected before the 1997 revisions to the PURA. Staff supports AIU's proposal.

a. IIEC Position

In support of its position, IIEC asserts that when Illinois restructured the electric utility industry, it also determined that it would change the basis of the PURA tax to keep it competitively neutral, while maintaining essentially the same level of tax revenues from each of the Illinois utilities individually and in the aggregate, through a series of charges designed to be applied to each utility's delivered energy. IIEC contends that this design protected the tax revenue stream from variation due to utility sale or transfer of generating or transmission assets, since such sale had the potential to reduce a utility's level of invested capital and thus its tax liability. In 1997, the level of tax on invested capital for the three utilities was about $4 million for CILCO, $9 million for CIPS (including the former Union Electric Company), and $23 million for IP.

As a protection for utilities and their customers, IIEC states that the aggregate level of electric PURA tax that the state could collect was capped at $145,279,553 in 1998, adjusted for growth in subsequent years at the lesser of 5% or the percentage increase in the CPI. IIEC reports that the cap has been exceeded every year from 1997 through 2007, prompting annual proportional refunds. IIEC expects that this is likely to be the case for the foreseeable future.

Traditionally, the PURA tax imposed on the utilities has been considered a recoverable test year expense and has been allocated among the rate classes in the COSS based on the classes' share of the cost of utility plant in service, since plant in service represented the capital investments of the utilities. Although the PURA tax was restructured in 1997, IIEC relates that in each of the delivery service rate cases initiated by AIU or their unaffiliated predecessors since 1997 (12 cases in all) the PURA tax has been allocated on the basis of plant in service. As indicated above, however, in the current case AIU proposes to change its allocation from one based on plant in service to one based on the number of kWh delivered to each class. IIEC complains that this proposal would have the effect of shifting millions of dollars of revenue responsibility from the small customer classes to the large customer classes. IIEC asserts that the change in allocation accounts for much of the large increases in delivery service charges proposed by AIU for the DS-4 customers, particularly those taking service at higher voltages.

IIEC opposes AIU's proposed change in the allocation of the PURA tax for four primary reasons. First, IIEC claims that AIU has not justified changing the PURA tax allocation method. In response to discovery requests from IIEC, AIU indicates that it does not have any documents regarding its determination that the traditional approach is no longer appropriate. According to IIEC, AIU's entire rationale for the change is that the annual tax is assessed to AIU based on the quantity of retail electricity delivered in Illinois, making it clearly driven by kWh sales and not based on plant assets. (See Ameren Ex. 16.0E Second Revised at 8)

In response, IIEC argues that kWh sales are only one of several factors, and not the main factor, that determine a utility's PURA tax responsibility in any given year. IIEC insists that the main factor determining a utility's PURA tax responsibility today is the utility's 1997 level of invested capital (and associated tax). The tier levels and tier rates in the PURA, IIEC continues, were custom-designed to approximate the same level of total tax revenue from all utilities and the proportion of tax paid by each utility, as the utilities paid based on their invested capital. IIEC contends that AIU's allocation of the PURA tax on the basis of energy delivered actually moves rate making away from cost causation, giving more weight to the words used to describe or compute the tax than to the actual causes of the tax assessed. IIEC maintains that AIU's proposal to change the only allocation basis it has ever used without any evidence of a change in cost causation and without any quantitative evidence of causation for kWh delivered is not consistent with cost causation principles or AIU's obligation to demonstrate that the change is just and reasonable.

Second, contrary to AIU's and Staff's suggestion, IIEC states that any correlation between kWh sales and the utilities' PURA tax liability in a given year is very weak--at least that is what IIEC says it found when it analyzed the actual kWh sales reported by AIU and the actual PURA tax payments. IIEC witness Stephens explains that if the level of usage determines the amount of PURA taxes, one would expect a linear positive relationship between the PURA tax and kWh deliveries, with the slope of the line representing the marginal (last block) tax rate. The actual AIU data, however, indicates a very weak explanative value of kWh deliveries for changes in the PURA tax, according to Mr. Stephens. He notes further that the slopes of the regressed lines are different from the applicable marginal tax rates set forth in the 1997 legislation. That is, the PURA taxes that a utility pays and kWh the utility delivers change at different rates. Mr. Stephens states that this is another indicator of lack of correlation between the kWh sales and expected tax levels. IIEC asserts that its analytic evidence was unrebutted by AIU or Staff, who rely instead on the simplistic, erroneous assertions that kWh sales drive or cause the utilities' PURA tax liability, without conducting any investigations of the actual cause of the tax liability incurred by the utility.

Third, IIEC maintains that the large majority of the current PURA tax is simply inherited 1997 invested capital tax. IIEC states that approximately 84% of the PURA tax assessed to AIU in 2008 was attributable directly to the 1997 invested capital taxes. Given the Commission's commitment to cost causation principles in setting rates, IIEC contends that it would be unreasonable and unfair to allocate the PURA tax entirely on the basis of energy usage, when nearly 84% of the tax is caused by historical utility plant investment unrelated to energy delivery. Furthermore, IIEC asserts that even the growth in tax liability post-1997 is closely tied to 1997 invested capital levels, through the utility-specific tax rates. IIEC insists that there is virtually no evidence to compel a change in the allocation of this significant cost item.

Fourth, IIEC argues that AIU's proposed allocation of the PURA tax is not consistent with the legislature's desire to maintain the 1997 invested capital tax levels and utility shares. IIEC states that Section 1a of the PURA describes the legislative intent of the statute. According to IIEC, the legislative intent clearly indicates that the legislature had two goals in mind: 1) to assess the tax in a way that would be fair, as between utilities and other energy suppliers in the restructured industry, and 2) to maintain tax levels, with comparable allocations among the utilities. IIEC states that no where in the law is there expressed an expectation that the redesign could shift tax burdens from one customer class to another.

With regard to the legislature's first purpose, IIEC explains that it was necessary to change the collection basis from utility invested capital to delivered kWh because the restructuring law paved the way for new electric suppliers who would not be utilities under applicable law. These new suppliers would not be regulated by the Commission, and might not own physical assets. The new suppliers would enter the Illinois market to compete against utilities or other suppliers that would have been subject to the invested capital tax. Moreover, IIEC continues, the 1997 restructuring law allowed utilities to sell or transfer capital assets to affiliated or unaffiliated third parties, with very limited Commission oversight. Thus, IIEC concludes, converting the form of the tax to a delivered energy calculation and collecting it only from the regulated delivery utilities leveled the playing field among competing suppliers.

With regard to the legislature's second purpose, IIEC states that the structure of the statute indicates that the legislature wished to maintain tax revenues comparable to the amount collected before the change in the law. Since the invested capital of the utilities in 1997 caused a specific level of PURA tax for each utility, IIEC states that it would not have mattered whether the legislation achieved its revenue neutrality by replicating the amount using a calculation based on per kWh rates or by simply enumerating each utility's starting tax level in the law. IIEC asserts that the same level of tax could be derived under any number of custom approaches; the Illinois Legislature happened to use the custom-designed per kWh approach. IIEC contends that the approach chosen by the legislature simply to maintain tax revenue stability does not dictate a shift in cost responsibilities among customer classes.

IIEC acknowledges that the Commission did approve an allocation based on kWh delivered in the initial ComEd delivery service rate case. (Docket No. 99-0117, August 26, 1999, Order at 40) IIEC suggests that the Commission did not, at that time, have the breadth of information on the tax, its cause, and the lack of correlation between kWh delivered and the amount of the tax that is contained in the record in this case. IIEC therefore believes that this record is distinguishable and requires a different result from that in the ComEd proceeding.

If none of its arguments persuade the Commission to retain the traditional allocation of the PURA tax, IIEC offers an alternative tax allocation method which it believes even more precisely allocates tax costs to cost causers. IIEC proposes that the Commission recognize the distinctive cost-causation of portions of the PURA tax by creating two separate cost categories for the tax in the COSS, with different allocation factors for each. The first cost category would be the 1997 levels of PURA tax for each utility. This cost category should be allocated on the traditional basis of utility plant in service. The cost should be recovered in the distribution delivery charge, as is currently the case. The second category of costs would reflect PURA tax amounts in excess of the 1997 levels. These are subject to increase over time as the PURA tax level grows with the escalators on the statewide cap. Under IIEC's alternative proposal, this second category of PURA tax, the "post-1997 PURA tax" could be allocated based on kWh sales, in recognition that kWh sales may, under some circumstances and in some years, be a contributing factor to PURA tax levels. The 1997 PURA tax and the increases in post-1997 PURA tax levels for each of the three utilities necessary for implementation of this approach are shown in Table 1 of IIEC Ex. 5.0 Corrected at 14-15. IIEC computed revised cost of service results based on this alternative approach and provided them in IIEC Ex. 5.2. IIEC believes that this alternative approach provides a reasonable and practical compromise position on this contentious issue, should the Commission seek such a compromise.

b. AIU Position

AIU maintains that IIEC's approach is inappropriate because the structure of the tax is such that as a utility delivers more or less energy, the amount of tax will increase or decrease, all other things constant. Such a result indicates that plant is not a determining factor of the tax amount, but rather that the amount of kWh delivered is determinative. AIU states further that the difference between AIU today and CILCO, CIPS, and IP in 1997 is that in 1997 each of the utilities owned its own generation facilities that were part of the utility plant in service and provided fully bundled electric service. AIU insists that allocating and assigning the cost based on kWh is far superior to allocating the tax based on costs that no longer include generation plant. AIU adds that its proposal to collect the electric distribution tax based on kWh sales is consistent with the legislative intent of the law. Accordingly, AIU urges the Commission to adopt its kWh-based proposal.

c. Staff Position

Staff maintains that AIU's proposal to allocate the PURA tax by usage is consistent with cost causation and should be adopted in this proceeding. Staff observes that since the 1997 revisions to the PURA, usage has determined the amount of distribution taxes collected from ratepayers. Since usage is the driver, Staff states that cost causation principles would argue for allocating these costs on a per kWh basis. Section 1a of the PURA clearly shows, according to Staff, that the legislature made a conscious decision to change the way the distribution tax is determined, from a tax based on invested capital to a tax determined by usage.

The proposal to change from a plant allocator to a usage allocator would shift responsibility for these tax costs from smaller to larger customers on the system. Staff relates that large DS-4 customers account for 43% of system usage and, therefore, would be allocated 43% of these costs in contrast to the 8% they now pay. Staff states further that the allocation to residential DS-1 customers would decline from 56% to 30% of these costs.

Staff notes that the Commission has a longstanding goal of basing rates on cost. Staff contends that IIEC's argument is flawed because cost causation, rather than precedent, should be the deciding factor in the allocation process. If an existing method of allocating a cost that the Commission has approved is not cost based, then the most equitable and efficient solution is to adopt a cost based approach.

Staff rejects IIEC's argument that the continued allocation of distribution taxes according to plant in service is justified on cost principles. Staff also denies that the current level of the tax is primarily a function of the past levels of plant assets, as IIEC contends. While the starting point for the tax levels after the amendatory act corresponded to previous tax levels that were based on invested capital, Staff asserts that the yearly changes for taxes as a whole for all Illinois utilities are not. Staff observes that each year the total amount of distribution taxes collected by utilities increases by the lesser of 5% over the existing level or by the yearly CPI. Neither of these factors, Staff points out, bears any relationship to plant investments.

Furthermore, Staff continues, plant in service is no longer considered in the calculation. If the level of plant were to double or to decline by half, that specific change would have no impact on the utility’s distribution tax. In contrast, Staff observes that the level of deliveries by electric utilities directly affects distribution taxes. If a utility’s level of deliveries increases relative to other electric utilities in Illinois, its share of distribution taxes will increase. If its relative level of deliveries decline, the utility’s share of the distribution tax total will fall. Staff believes that it is clear that usage is the driver now.

There is no doubt that the legislature initially set the level of PURA taxes for each utility calculated on a usage basis approximately equal to the level under the previous plant-based method. Staff asserts, however, that the legislature made it explicitly clear that this tiered method of allocating PURA taxes to utilities would be based on a going-forward basis according to usage, not plant. There is no ambiguity in Staff's opinion that the legislature intended to replace the invested capital tax on electric public utilities with a new tax based on the quantity of electricity that is delivered. Staff notes further that the PURA goes on to state that this usage-based approach is fairer and more equitable.

Staff goes on to suggest that the continued allocation of these costs by the plant in service method directly conflicts with the intent of the law.

d. GFA Position

GFA expresses concern over the impact on larger customer's bills that collecting the PURA tax on a per kWh basis may produce. If the Commission adopts the AIU/Staff proposal for recovering the PURA tax, GFA respectfully suggests that the Commission consider alternatives that would mitigate some of that bill impact.

e. Commission Conclusion

At the outset, the Commission recognizes that allocation of the PURA tax among the electric rate classes involves millions of dollars. Properly assigning these tax costs to the cost causers is clearly important to both customers and the Commission. What drives these tax costs, however, is not entirely clear. IIEC makes interesting arguments in support of its position that invested capital (or plant in service), and not kWh, is the primary cost causer in this instance. IIEC relies on the fact that prior to 1997 plant in service was the basis for the PURA tax. IIIEC maintains that the legislature did not intend to alter this approach when it amended the PURA in 1997.

AIU, Staff, and IIEC each make compelling arguments for and against allocating the PURA tax on the basis of either plant in service or kWh. To resolve these competing concerns, a review of the PURA is necessary. Section 1a of the PURA addresses legislative intent and provides as follows:

> The General Assembly previously imposed a tax on the invested capital of electric utilities to replace in part the personal property tax that was abolished by the Illinois Constitution of 1970. Subsequent to the enactment and imposition of the invested capital tax on electric utilities, State and federal laws regulating the provision of electricity have been enacted which provide for the restructuring of the electric power industry into a competitive industry. In response to this restructuring, this amendatory Act of 1997 is intended to provide for a replacement for the invested capital tax on electric utilities, other than electric cooperatives, and replace it with a new tax based on the quantity of electricity that is delivered in this State. The General Assembly finds and declares that this new tax is a fairer and more equitable means to replace that portion of the personal property tax that was abolished by the Illinois Constitution of 1970 and previously replaced by the invested capital tax on electric utilities, while maintaining a comparable allocation among electric utilities in this State for payment of taxes imposed to replace the personal property tax.
> (Source: Public Act 90‑561, eff. 1‑1‑98.)

This section leaves no doubt that the legislature intended to replace the invested capital/plant in service tax with a kWh tax in response to the changing nature of the Illinois electric utility industry. Also apparent from this language is that the legislature did not want to lose any tax revenue as a result of this change. What remains unclear to the Commission, despite IIEC's assurances, is that the legislature did not intend for any change in how a utility's PURA tax liability is allocated to customers.

While it is true that the statutory language does not expressly direct that the manner in which the tax is allocated be changed, the language also does not require that the allocation method remain the same. The Commission notes that shortly after the revisions to the PURA took effect, it approved allocating the PURA tax on a kWh basis for ComEd in Docket No. 99-0117. Either ComEd's current allocation approach is appropriate or it has been contrary to the legislative intent behind the PURA revisions for nearly 11 years. If the former characterization is accurate, and AIU has been allocating the PURA tax contrary to the legislative intent, nothing prevents the Commission from correcting such an oversight in this proceeding.

In resolving this issue, the Commission notes that the legislature clearly contemplated that regulated electric public utilities might shed much of their plant in service (primarily generation assets) and become regulated distribution utilities. Hence, the need to modify how the PURA tax was assessed. The possibility that the legislature contemplated has occurred, and much of that plant in service is no longer owned by the regulated electric utilities. The disconnect between plant in service and the distribution tax under the current PURA provisions is apparent from the fact that as the level of a utility's plant increases or decreases, that specific change would have no impact on the utility’s distribution tax. A break from historic plant in service is also suggested in Section 2a.1 of the PURA, which imposes an annual cap on the aggregate amount of the distribution tax which can be collected statewide from electric public utilities and ARES, as those terms are defined in the Act. As a practical matter, no ARES deliver electricity. But if one ever did using its own plant in service, it would have no historic invested capital value for the legislature to try to preserve through the per kWh tax rates in the PURA.

For these and the foregoing reasons, the Commission is inclined to find the interpretation of the PURA by AIU and Staff more reasonable than that of IIEC. Adoption of the AIU and Staff position is also consistent with Docket No. 99-0117. If the legislature intended a different result, the Commission would welcome any such clarification. In the absence of any clear legislative intent to the contrary, AIU should recover PURA tax costs in base rates through the kWh-based Distribution Delivery Charge from the DS-1, DS-2, and DS-5 classes. AIU should create a kWh charge to reflect the PURA tax allocation that applies to the DS-3 and DS-4 classes.

4. Overall Suitability of AIU's COSS

AIU presented a separate electric COSS for each of the three utilities using a test year of 12 months ending on December 31, 2008. AIU's proposes rates based on the

COSS. IIEC contends that AIU's electric COSS are riddled with errors and should not be relied upon. Instead, IIEC recommends that the Commission allocate any rate change approved in this docket on an equal percentage, across-the-board basis. Staff generally supports AIU's electric COSS (but recommends specific revisions discussed below).

a. AIU Position

AIU explains that the class COSS presented in these cases are the result of the process of allocating and assigning the various cost elements of providing electric delivery service to the various customer classes in a way that best reflects the manner in which such costs are incurred in providing delivery service. The results of the class COSS are often referred to as the “class revenue requirements.” AIU identifies three steps in preparing a COSS: functionalization, classification, and allocation. Functionalization is the assignment of rate base items and operating expenses to major functions such as production, transmission, distribution, and customer service. Classification is the assignment of the functionalized costs to categories of cost causation. For example, costs may be classified as demand-related, energy-related, or customer-related. Allocation is the process of assigning the classified costs to the various classes of service.

With specific regard to the classification step, AIU states that it classifies each rate base and expense item in the electric delivery revenue requirement on the basis of cost causation to demand-subtransmission, demand-distribution, or customer. Demand-subtransmission and demand-distribution costs, AIU continues, are those investments and expense items that are incurred to meet system peak load requirements and local maximum demands, respectively. AIU relates further that customer-related costs are those investments and expense items which are incurred to serve customers and which do not vary with changes in consumption, such as the cost of the customer’s meter and service drop.

In the development of distribution plant in the COSS model, AIU explains that the capital asset costs are segregated according to voltage level. AIU indicates that demand-related costs were allocated to customer classes based on the contribution of each customer class to the system’s NCP demand based on the costs at the various voltage levels.

AIU asserts that its COSS preparation methodologies were approved by the Commission in its Order in Docket Nos. 06-0070 et al. (Cons.), AIU's second most recent electric delivery service rate proceeding. AIU notes, however, that some allocation factors were modified to more appropriately follow current operations and customer demand. Ameren Ex. 17.0 contains a discussion of AIU's allocation methodologies.

After reviewing the other parties' positions, AIU identified one necessary change to the COSS. Specifically, AIU realizes that the allocator used to determine how FERC

Account 362 (reflecting costs for distribution substations) is allocated to customers was initially incorrect. AIU now agrees with IIEC that the DDSUBTR allocator should be used to allocate the costs in FERC Account 362. AIU explains that the DDSUBTR allocator is more appropriate because it selectively allocates the costs in Account 362 to customers with delivery voltage less than 100 kV. AIU adds that the change to the DDSUBTR allocator is proper because it more closely matches the function of the substations – lowering the supply voltage down to delivery voltage. According to AIU, adoption of the DDSUBTR allocator results in the reallocation of approximately $25 million to the DS-4 100+ kV customer subclass, out of $4.3 billion in total AIU allocable gross distribution plant. AIU states that the $27 million value cited by IIEC is a gross number before depreciation is applied, and ultimately translates into a revenue requirement reallocation totaling approximately $4 million (calculated as ROR multiplied by cumulative depreciation, less allocation depreciation, plus allocation depreciation expense) of associated revenue requirement to the DS-4 100+ kV customer subclass. The practical effect is that the revenue requirement reallocation will not reach $4 million if the Commission approves a revenue requirement lower than what AIU requests.

Even with the correction regarding the DDSUBTR allocator, AIU does not assert that its COSS are perfect. AIU acknowledges that assigning specific costs to broad rate classifications involves some subjective consideration, which includes some degree of generalized application and educated assumption. Regardless, AIU maintains that it is the steward of the COSS it maintains. AIU indicates that it is always willing to redress legitimate concerns regarding the study, as well as any similar models offered by Staff and customers. AIU is confident that its COSS presents a highly accurate allocation of cost causation. AIU states that it will continue to address stakeholder recommendations that could enable it to allocate costs more precisely in future rate cases. AIU urges the Commission to accept its COSS in this proceeding. To the extent that modifications have been proposed in this case, AIU asks that the Commission refrain from rejecting its COSS and instead direct that such modifications be implemented in future COSS.

Regarding the errors in the AIU COSS that IIEC claims to have identified, AIU points out that IIEC nevertheless used AIU's study rather then create its own. Concerning IIEC's allegation that AIU misallocates the PURA tax, AIU insists that its allocation is consistent with the statutory assessment of the tax. AIU also denies that its use of the NCP demand allocator is inappropriate. AIU maintains that IIEC provides little more than conclusory assumptions and generalized criticism of the NCP allocator that is unsupported by the record. As an example, AIU points to IIEC's claim that AIU fails to allocate the costs of poles, wires, and substations to nearly 2,000 large customers taking service at secondary voltage. AIU contends that IIEC cites no evidence to support this assertion. As for the allegedly ambiguous voltage definitions which IIEC complains of, AIU asserts that this is merely another iteration of IIEC’s misplaced argument that AIU's use of both supply and delivery voltages in the cost allocations for large (100+ kV) customers is inappropriate. AIU also asserts that it provided responses to all of IIEC's discovery requests in a timely manner.

With respect to IIEC's complaints regarding allocation of transformer revenue, AIU argues that its approach is reasonable. AIU explains that transformer rental revenue, like other forms of revenue, is an off-set to the overall revenue requirement—which AIU states it recognized when it allocated that revenue in the COSS. Although IIEC contends that AIU has misallocated transformer rental revenue, it presents no alternative approach. If IIEC had proposed an alternate approach, AIU states that it would have considered it. Instead, IIEC merely reiterates its argument that AIU's COSS are not perfect, and as a result, the Commission should reject them in their entirety.

In response to IIEC's claim that the COSS reflect a discrepancy in the number of DS-2 customers, AIU contends that IIEC misinterprets AIU witness Althoff's testimony, as well as the data in Schedule E-6. During Ms. Althoff's cross-examination, AIU relates that IIEC displayed certain customer count statistics on the E-6 schedule. AIU asserts, however, that those statistics are unrelated to the metered delivery points utilized in AIU's COSS. Ms. Althoff noted during her examination that there are various customer count and delivery service point metrics, many of which are related to one another to some extent. AIU maintains that minor differences among these statistics are not indicative of underlying problems with the data it used in the COSS. AIU states further that it used customer count data by class to allocate certain costs, and NCP demand to allocate others. To the extent that the IIEC is suggesting differences between customer counts, meters, and delivery points are indicative of missing information, AIU contends that IIEC is simply presenting an apples-to-oranges comparison.

Because of the errors that it perceives in AIU's electric COSS, IIEC recommends that the Commission revise rates on an across-the-board basis rather than rely on the allegedly faulty COSS. AIU takes exception to this proposal and notes that IIEC advocates this position for the first time in its Initial Brief. AIU also points out that in AIU's last rate proceeding, Docket Nos. 07-0585 et al (Cons.), IIEC was steadfast in its support of cost based rates and openly criticized AIU for proposing an across-the-board increase in rates.

AIU notes further that during the course of the hearing, IIEC raised the notion of rerunning the COSS. AIU contends that this would not be a useful exercise and would not benefit the Commission's consideration of the issues in this case. According to AIU, utilities do not typically completely rerun a COSS during a rate case. Expanding the evidentiary phase of the case, AIU adds, only prolongs and complicates an already arduous process. AIU asserts that the COSS is merely a foundational step that is only conducted to provide support for its ultimate rate design recommendations. Absent the rate design considerations it is intended to support, AIU contends that a COSS update would not provide any additional analytical value. The revenue requirement values entered into the COSS at the beginning of the case will change as a result of the Commission's decision in these cases. AIU maintains that conforming the rate design to the final revenue requirement, both at aggregate and class levels, should not be addressed by reopening the evidentiary record. Instead, AIU believes that the final revenue requirement is more properly addressed by reference to witness testimony specific to that very subject. In this instance, AIU states that AIU witness Jones and Staff witness Lazare have offered testimony with regard to the methodology utilized to adjust proposed rates to the final revenue requirement.

b. IIEC Position

IIEC's criticism of AIU's electric COSS begins with the observation that the results of any COSS are only as valid as the inputs and assumptions used to develop the study. In this instance, IIEC contends that AIU's COSS contain errors in logic and factual inconsistencies that render them deficient for the purpose of setting rates in this proceeding. IIEC asserts that some of these errors and inconsistencies were identified in its written direct and rebuttal testimonies, while others were identified through cross-examination. In its direct testimony, IIEC claims to have identified (1) the misallocation of the cost of 34.5 kV and 69 kV substations (in FERC Account 362) to customers taking services at a voltage of 100 kV or higher, (2) the misallocation of PURA taxes, (3) errors in the development of the NCP demand allocators, and (4) a failure to properly allocate transformer rental revenue.

Regarding the alleged misallocation of the cost of 34.5 kV and 69 kV substations, IIEC claims that the AIU COSS allocated these sub-transmission costs to transmission level customer classes that take service at 100 kV or higher. IIEC suggests that in total, AIU's COSS improperly allocated $27 million in primary voltage and/or sub-transmission voltage substation equipment costs to transmission level customers. IIEC points out that the misallocation of these costs appeared to be associated with a change in the allocation factor used to distribute sub-transmission station equipment in the current studies. In the current studies, AIU used a factor identified as "DEMSUBTR." IIEC observes that in its prior COSS AIU used the DDSUBTR allocator, which IIEC believes properly allocates sub-transmission substation costs. Although AIU eventually agreed with IIEC that use of the DEMSUBTR allocator was an error, IIEC notes that AIU's acquiescence does nothing to remedy the COSS at issue which incorporates the DEMSUBTR allocator.

As for the new demand study component of AIU's COSS, IIEC understands AIU to believe that its new studies are more reflective of the demand incurred on the secondary voltage portion of its distribution system with respect to the DS-2 class. IIEC, however, contends that the new study actually results in the allocation of costs used to serve customers at secondary voltage levels to customers who do not use the secondary system. Specifically, IIEC states that the study does not distinguish between DS-2 customers taking service at primary voltage and DS-2 customers taking service at secondary voltage. Therefore, IIEC argues that it is difficult to see how the new study is more reflective of demand incurred on the secondary voltage portion of the system with respect to the DS-2 class if it attributes secondary system costs to customers who do not use that system. IIEC also fears that AIU has not properly counted the number of DS-2 customers.

IIEC further complains that AIU's COSS for AmerenIP does not allocate costs relating to substation equipment, poles, towers, fixtures, overhead conductors and devices, and underground conduit reflected in FERC Accounts 362, 364, 365, and 366 to 1,936 DS-3a, DS-3b, and DS-4 secondary customers. IIEC contends that a similar situation occurs in the AmerenCIPS and the AmerenCILCO COSS. IIEC acknowledges AIU's suggestion that because these DS-3a, DS-3b, and DS-4 secondary customers are really supplied at primary voltage, the costs reflected in Accounts 362, 364, 365, and 366 would not be assigned to these customers. In IIEC's view, however, AIU's response calls into question class definitions in the AIU COSS. If classes clearly identified in the study as "secondary" are, in fact, supplied at primary voltage levels, IIEC does not understand how one can possibly determine, based on the COSS, whether secondary and primary costs have been properly allocated.

IIEC is also troubled by the testimony of AIU witness Althoff at the evidentiary hearing that the term "secondary" for the DS-3a secondary, DS-3b secondary, and DS-4 secondary classes refers to "metered voltage," and are totally separate and different from supply voltage and delivery voltage as AIU has used those terms in this case. (See Transcript at 586-587) IIEC states that AIU does not explain the significance of the term "metered voltage" in its description of its COSS. According to IIEC, Ms. Althoff's cross-examination testimony conflicts with her prepared written testimony wherein she stated that all customers have a supply and delivery voltage, where the supply voltage is the voltage of the feeder line from which the customer is supplied, and delivery voltage is the voltage at the point of connection between the customer's facilities and the AIU facilities. (Ameren Ex. 41.0 at 7) Under the circumstances, IIEC contends that it is difficult to see how the Commission can determine whether or not the AIU COSS in this case have properly identified the cost of serving these customer classes.

With regard to the assignment of transformer rental revenues, IIEC claims to have identified an error in the way AIU's COSS credited transformer rental revenues to the customer classes. AIU agrees that the revenues in question should be credited as closely as possible to the classes from which those revenues are collected. In the AIU COSS, however, IIEC notes that the transformer revenues were allocated on the basis of each class' contribution to NCP demand as determined by the new demand studies. As a result of AIU's improper treatment of rental revenues, IIEC contends that customer classes from which rental revenues are collected do not receive the full credit of that revenue. This in turn, IIEC continues, understates the rate or return developed in the COSS for the customer classes that contributed to the rental fees. At the same time, the customer classes with relatively large contributions to peak demand are credited with a relatively large portion of the rental revenues, irrespective of the amount of rental revenues actually contributed by those classes. Although AIU has expressed a willingness to correct this error in the next rate case, IIEC asserts that waiting until then does little to help determine the cost of serving these classes in this case.

IIEC states that it re-ran the AIU COSS to correct for the first two deficiencies. The correction of these two deficiencies alone, IIEC avers, had a significant impact on the class rates of return and the revenue allocations in each of the COSS. As an example, IIEC states under the revised COSS, the DS-4 class as a whole provided higher rates of return than AIU's original studies suggested and that the DS-4 100 kV and above subclass provided rates of return significantly above the total rates of return for each of the three utilities. IIEC indicates that it did not receive the data it needed to modify the NCP demand data allocators from AIU in a timely manner, and was therefore, unable to correct the third deficiency in the COSS.

When all of these errors and inconsistencies are considered, IIEC argues that the fundamental validity and accuracy of AIU's COSS are called into question. Unfortunately, IIEC continues, analyses or alternate versions of the COSS, such as its own, that are based on AIU's flawed COSS are themselves flawed (although perhaps to a lesser degree). Under the circumstances, IIEC asserts that the Commission can not be sure that the costs of serving the classes and subclasses within each of the three utilities have been accurately and properly determined. Therefore, it is IIEC's primary recommendation in this case that the Commission reject the use of AIU's COSS for revenue allocation and rate design purposes, and allocate any increase authorized in this case on an equal percentage across-the-board basis. At a minimum, if the Commission decides to use AIU's COSS for rate design and revenue allocation purposes, IIEC urges the Commission to correct the COSS for at least the deficiencies IIEC identifies.

c. Staff Position

Staff contends that the fact that only AIU offered a COSS does not mean that AIU's arguments on related issues should carry more weight. Staff points out that utilities are required to provide such studies under Part 285. Moreover, Staff continues, utilities are typically the source of COSS in rate cases because it is their overall costs that are being allocated among customer classes. Staff adds, however, that there is no guarantee that a utility's COSS is accurate. As an example of inaccuracies in COSS, Staff notes that AIU proposes to change the allocation of PURA taxes in this case as a delayed reaction to legislation passed in 1997. Thus, Staff reasons, AIU's action in this case corrects an inappropriate allocator from previous cases. Staff notes that AIU also accepts a revised allocator for Account 362. Staff contends that these are not the only shortcomings with AIU's COSS, noting its arguments regarding the allocation of primary lines and substations costs. Staff maintains that each cost of service argument should be assessed on its own merits and the fact that AIU furnished the original COSS for this case should not influence the Commission's decision on this issue in any manner.

d. Commission Conclusion

By AIU's own admission, its electric COSS are not perfect. The question for the Commission is whether the COSS are too imperfect to be used in this proceeding. The Commission recognizes that it approved use of similar electric COSS in AIU's second most recent rate proceeding, Docket Nos. 06-0070 (Cons.). The fact that AIU modified the COSS since then, however, warrants fresh consideration.

Some of the alleged errors in the COSS have already been reviewed and addressed in this Order. AIU acknowledges that use of the DEMSUBTR allocator was in error and has agreed to renew use of the DDSUBTR allocator. IIEC's concerns about the class demand study employing a combination of supply and delivery voltage have been considered above as well. The Commission concluded that the class demand study should use supply voltage alone. Allocation of AIU's PURA tax liability has also already been discussed, with the Commission concluding that no change in the COSS is warranted in this respect.

One of IIEC's criticisms that has not been previously addressed pertains to the allocation of transformer rental revenue. Whether AIU acknowledges a possible error in its allocation method is not clear. AIU does, however, allege that IIEC failed to provide it an alternative to consider. The Commission understands IIEC to simply argue that transformer rental revenue from DS-4 customers should be used to offset the DS-4 class revenue requirement. IIEC seems to make the same straightforward argument for the DS-3 class. The Commission agrees with IIEC's recommendation. Under IIEC's approach, the revenues in question will be credited to the classes from which those revenues are collected. To the extent that AIU's method differs in its COSS, the Commission directs AIU to implement IIEC's straightforward approach to allocating transformer rental revenue the next time it runs its COSS.

With regard to IIEC's complaint that AIU's COSS fails allocate costs relating to substation equipment, poles, towers, fixtures, overhead conductors and devices, and underground conduit reflected in FERC Accounts 362, 364, 365, and 366 to over 2,000 DS-3a, DS-3b, and DS-4 secondary customers, the record lacks sufficient evidence to find that IIEC is correct. If AIU has not allocated such costs to all of the appropriate customers, the Commission certainly expects AIU to be more careful the next time that it runs its COSS.

Despite having confirmed the presence of some of the errors that IIEC alleges, the Commission is not prepared to disregard AIU's electric COSS. In AIU's last rate proceeding, the Commission authorized rate adjustments on an across-the-board basis, not because of deficiencies in AIU's COSS but because the recently redesigned electric rates stemming from Docket No. 07-0165 had been in effect for less than one year. The Commission feared that returning to cost based rates so soon would lead to the same rate shock that warranted the rate redesign in Docket No. 07-0165. Since then, electricity commodity prices have dropped (for now) and the Commission generally believes that the overall impact of bills reflecting cost based delivery services will be tolerable. Therefore, the Commission finds that AIU's electric COSS, as modified in this Order, should be used in setting rates in this proceeding. IIEC may be correct regarding the other errors that it alleges exist in AIU's electric COSS, but the Commission does not consider them fatal to the COSS. AIU should therefore rerun its COSS incorporating the corrections and adjustments discussed above before finalizing rates.

C. Contested Gas Issue - Storage Cost Allocation

AIU incurs storage costs associated with both on-system storage facilities and off-system storage facilities. On-system underground storage facility costs are recovered in base rates. Off-system underground storage facility costs are recovered only from sales customers through a different recovery mechanism and are not at issue in this proceeding. In its gas COSS, AIU allocates such on-system costs to both sales and transportation customers.[11] AIU segregates these on-system storage costs into a portion that supports the delivery function applicable to all sales customers and a portion assignable to transportation customers based on their actual peak day usage during the historic test year. Staff, on the other hand, proposes to allocate these costs based on the transportation customers' Daily Confirmed Nomination ("DCN")[12] on the same day. Nominations are the amount of gas scheduled for delivery on a pipeline to the LDC system.

1. AIU Position

Transportation customers have a limited ability to withdraw gas from their transportation banks on a peak day. AIU bases the on-system underground storage cost allocation on the relative size of the transportation customers' withdrawal ability. On a Critical Day ("CD"), daily balanced customers can call on their storage bank for up to 20% of their DCN and monthly balanced transportation customers can call on the storage bank for up to 50% of their DCN. AIU states that it must operationally plan to serve transportation customer banks on a CD, but does not know what the transportation customers will nominate on any given day in the future. From a planning perspective, AIU assumes that transportation customers as an aggregate will call on the storage bank for 20% of their usage on a future peak day. AIU, therefore, determined the amount of on-system storage capacity planned to serve 20% of the transportation customers' peak day usage and allocated a portion of the on-system storage capacity costs based on the ratio of the transportation customers' peak day capacity usage to the total on-system storage capacity.

AIU's proposed allocation of on-system underground storage costs to transportation customers is based on the transportation customers' actual peak day usage during the 2008 test year. The following table shows the how AIU determined the allocation percentage for AmerenCIPS. In this example, AmerenCIPS' 2008 peak day usage was 60,436 therms. Excluding the usage associated with special contracts and GDS-7 customers results in 34,204 therms of relevant peak day usage. Applying

[11] AIU provides two general categories of service to its commercial customers: they can either receive sales service (i.e., AIU sells and delivers gas to the customer) or transportation service (i.e., AIU delivers to the customer gas that the customer purchased from a third party).

[12] As defined AIU's tariffs, a DCN is the volume a transportation customer nominates and delivers to the company's delivery system for any single day. The absence of a DCN is equivalent to a DCN of zero. Such deliveries shall reflect adjustments for losses on the company's gas system. (See Ill. C. C. No. 20, 1st Revised Sheet No. 25.001)

AIU's actual 20% planning assumption to the 34,204 therms of relevant transportation customer peak day usage results in an expected bank withdrawal of 6,841 therms. AmerenCIPS has 38,000 therms of on system storage capacity. The 6,841 therms of expected bank withdrawal rights represents 18.00% of the 38,000 therms of on-system storage capacity available to the transportation customers.

	Calculation of the Transportation Customers' Allocation of On-System Storage Facility Costs	AmerenCIPS
(a)	Transportation customers' relevant 2008 peak day usage	34,204 therms
(b)	Planning Factor	20%
(c)	Bank Withdrawal Rights – *i.e.,* (a) times (b)	6,841 therms
(d)	Total On-System Storage Capacity	38,000 therms
(e)	Allocation Percentage – *i.e.,* (c) divided by (d)	18%

AIU therefore allocated 18% of AmerenCIPS' on-system underground storage costs to the AmerenCIPS transportation customers. The remaining 82% of the on-system storage costs was allocated to sales customers. Using the same methodology, AIU produced allocation percentages for AmerenCILCO and Ameren IP. AIU offers the following table depicting the percentage of on-system underground storage costs allocated to transportation customers under the AIU and Staff proposals. AIU and Staff disagree not only on the resulting allocation percentages, but also on the method for developing those percentages.

Proposed Allocation of On-System Storage Costs to Transportation Customers		
	AIU Allocation Based on Actual Planned Peak Day Usage (Ameren Ex. 27.3)	Staff Allocation Based on DCN (Staff Ex. 27.0 Revised at 38)
AmerenCIPS	18.00%	14.02%
AmerenCILCO	5.53%	3.96%
AmerenIP	5.21%	3.80%
Total	6.19%	4.55%

AIU, therefore, bases its proposed gas rates on the following allocations of on-system storage costs to transportation customers: (a) AmerenCIPS – 18.00%, (b) AmerenCILCO – 5.53%, and (c) AmerenIP – 5.21%. These percentages are based on the transportation customers' ability to rely on these facilities to serve their peak day usage with bank withdrawals.

Rather than allocate costs based, in essence, on the AIUs' planned deliverability to customers (i.e., the amount of capacity that AIU actually acquired and accounted for in its peak day planning for these customers), Staff recommends that AIU allocate on-system storage costs based on 20% of the transportation customers DCN on the 2008 test year peak day. The DCN for that peak day represents the amount of gas that the transportation customers intended to deliver for that peak day. Staff claims that it is more appropriate to allocate the on-system storage cost based on a percentage of DCN because AIU's tariffs allow transportation customers to call their bank capacity for up to 20% of their DCN. AIU contends that Staff's proposal is flawed.

AIU's first criticism of Staff's approach is that using only the DCN understates the cost responsibility to transportation customers with the remaining cost responsibility being absorbed by sales customers. AIU maintains that its approach of using actual peak day usage mirrors more closely a true and reasonable design day level requirement from which costs can be reasonably assigned to transportation customers. AIU's second criticism is that transportation customers' DCN is discretionary and not predictable. A transportation customer can nominate as little as zero therms for a peak day, as much as 100% of the maximum daily contract quantity ("MDCQ") for daily-balanced customers, or 200% of MDCQ for monthly balanced customers. AIU states that it is up to each transportation customer to decide how much gas to nominate on a day. The customer may not be able call on storage bank if, for example, the customer did not have a positive bank balance. Moreover, AIU adds, the customer may choose not to call on its storage bank for a commercial reason. Alternatively, AIU states that transportation customers can call on the transportation bank for as much as 20% to 40% of their MDCQ if they nominated the maximum amount available under the tariff. AIU does not know what a transportation customer individually, or transportation customers in aggregate, will nominate for any given day. Due to the discretionary nature of the DCN, AIU does not plan its resources assuming 20% of historic DCN.

AIU disagrees with Staff's contention that basing the allocation on 20% of peak day usage rather than 20% of DCN over-allocates costs to transportation customers. While DCN levels are a fair starting or reference point, AIU maintains that the transportation customers' DCNs are significantly lower than the transportation customers' actual peak day usage. Basing the on-peak storage allocations on transportation customers' DCNs would materially understate the storage cost responsibility to transportation customers, according to AIU. Instead, when allocating the storage costs, AIU states that it should consider not only the starting DCN, but also the actual peak day use of transportation customers. AIU concludes that the Commission should permit it to allocate on-system storage costs based on the transportation customers' peak day usage that would capture the initial DCN levels, plus rather large additional levels of use.

2. Staff Position

Staff has no objections to the allocation of on-system underground storage facility costs based on the ability to withdraw gas on a peak day. Staff notes, however, that while AIU reasonably allocates these costs based on ability to withdraw gas on a peak day, it measures that ability as 20% of transportation customers' usage rather than the smaller amount allowed in the tariff, which is 20% of a customer's DCN for GDS-4 customers. DCN is the amount that the pipelines have confirmed will be delivered. Staff states that AIU treats any volume of gas that a customer uses above its DCN as a bank withdrawal. Therefore, on days where a customer expects to withdraw gas from its Rider T bank as is assumed in allocating storage cost responsibility, AIU assumes that the customer will nominates a volume of gas less than its anticipated usage. Staff asserts that AIU acknowledges that DCN will be less than usage and 20% of DCN will be less than 20% of usage. (Tr. at 856-857) According to Staff, the practical result of AIU using 20% of usage is to over-allocate storage costs to transportation customers. Consistent with AIU's tariffs that provide that transportation customers may withdraw 20% of their peak day DCN, Staff recommends that these customers be allocated the share of storage costs based on 20% of DCN rather the 20% of their peak day usage.

Staff asserts that AIU set out to allocate storage costs to transportation customers “based on the transportation customers’ actual peak day usage during the historic test year,” and “based on their ability to withdraw gas from their transportation banks on a peak day." (AIU Initial Brief at 218) Staff notes that these are not the same thing. AIU later offered a third reason: that 20% of usage (an amount in excess of tariff limits on withdrawals) represents “expected bank withdrawals” on a design day. (AIU Initial Brief at 220) Staff criticizes AIU for changing the reason behind its allocation method.

Staff understands that AIU has designed the gas distribution system for a CD. Therefore, Staff believes that it is appropriate to compare the relationship between expected usage and DCN on a CD, rather than simply on an historic peak day. AIU, however, continues to argue that bank withdrawals will be in excess of that allowed in the tariff. Staff states that AIU bases this view on the assumption that customers will under-nominate on a CD. Staff argues that under-nomination on a CD is unlikely in light of the tariff conditions that exist on CDs. For example, usage in excess of nominations and allowed bank withdrawals are subject to significant penalties of over $6 per therm.

In response to AIU's assertion that it can not predict DCN on peak days and therefore relies on usage, Staff acknowledges that it may be easier to estimate usage on peak days but contends that DCN on a CD must be close to usage. If AIU has chosen to plan its system based on bank withdrawals that are not supported by the tariff, Staff states that this should not influence cost allocation. Staff contends that transportation customers should pay based on what they can expect to withdraw on a CD. Staff relates that it is neither usage alone nor DCN alone that dictates the level of bank usage; rather, it is the difference in DCN and usage. On a CD, Staff explains that these numbers will closely track because of AIU’s tariff provisions approved by the Commission to prevent one thing: the excess use of system gas that results from under-nomination.

With respect to AIU's complaint that the transportation customers’ DCN is discretionary and not predictable, Staff counters that just because customers' nominations are “discretionary” does not make them arbitrary as AIU infers. Staff maintains that AIU has not established that its transportation customers individually vary their nominations between 0 and 200% despite the allegation to that effect. Certainly this will not be the case, Staff continues, when transportation customers are considered in aggregate--which is what is what is at stake here. According to Staff, the maximum aggregate that AIU alleges individual transportation customers can nominate is not the issue here because if transportation customers nominate and deliver up to MDCQ or even 2 times MDCQ on a peak day, they would be injecting gas, not withdrawing it. Staff observes that such nominations would only cause the transportation customers' aggregate bank usage to go down.

Staff goes on to state, however, that the minimum aggregate expected nomination would be a legitimate concern. On a CD, Staff relates that transportation customers have certain "rights" to nominate as stated by AIU; they have certain obligations as well. Realistically, Staff doubts that transportation customers would nominate that little gas. The factor limiting potential under-nomination, Staff continues, is CD penalties. All transportation customers, regardless of whether they are daily or monthly–balanced customers, face the $6-per-therm Unauthorized Gas Use Charge which could be 10 times the price of gas on that day or more. In addition, Staff reports that transportation customers would also face stringent Operational Flow Order ("OFO") balancing provisions that charge transportation customers up to 2 times the spot price for the use of system gas. Furthermore, transportation customers stand responsible for potential pipeline imbalances that they may cause. Staff argues that all of these things combine to constrain transportation customers' nominations to a reasonable level. AIU's assertion of wildly vacillating nominations between 0 and 200% of MDCQ is simply not realistic, according to Staff, in light of AIU's exiting tariff terms. Staff maintains that AIU focuses on serving the bank withdrawals of transportation customers and ignores the other side of the tariff that is designed to protect the system on a CD.

AIU also indicates that some customers may not be able to withdraw gas on the CD because they may lack sufficient capacity in those banks. These customers, AIU states, will have to nominate below their usage to reduce the risk of Unauthorized Gas Use Charges, which would reduce the aggregate bank withdrawal below the 20% amount. Staff observes that another reason listed by AIU is that customers may choose to not use banks for commercial reasons. Staff states that this would once again mean that they would have to nominate more than they would otherwise and would also reduce the aggregate bank withdrawal. According to Staff, these examples of discretionary behavior actually point to a lower expected bank withdrawal. Staff contends that AIU can not point to a singe reason why transportation customers would reduce nominations on a CD and completely ignores the CD penalties which may be 10 times the market price or more.

Therefore, Staff continues to recommend that these customers be allocated the share of storage costs based on tariff rights that provide withdrawals of 20% of DCN rather the 20% of their peak day usage. Using 20% of DCN changes the storage allocator in Ameren Ex. 27.3 from 18.00% for AmerenCIPS to 14.02%, from 5.53% for AmerenCILCO to 3.96% and from 5.21% for AmerenIP to 3.80%.

3. Commission Conclusion

Generally, the Commission approves of allocating on on-system underground storage costs based on the relative size of the transportation customers’ withdrawal ability on a peak day. While AIU bases the allocation on 20% of transportation customers' aggregate usage on the 2008 peak day, Staff recommends basing the allocation on 20% of transportation customers' aggregate DCN on the 2008 peak day. There is no dispute that 20% of usage is a greater number than 20% of DCN on the peak day. Nor is there a dispute that AIU's method allocates more on-system storage costs to transportation customers that Staffs' method. The question is which method is more representative of costs transportation customers impose on the storage system.

While AIU's method attempts to consider bank withdrawals by transportation customers on a CD, when storage capacity is arguably the most important, the Commission is concerned that AIU has neglected to consider the big picture. By "big picture," the Commission is referring to AIU's existing tariff provisions which would deter transportation customers from making a reliability problem worse on a CD. Staff's method, on the other hand, appears to reflect the operational realities of a CD. The Commission finds Staff's approach to more reasonably reflect the withdrawal capacity of transportation customers on a peak day. Basing the allocation on 20% of peak day usage rather than 20% of DCN over-allocates costs to transportation customers. The more appropriate method is to allocate the on-system storage cost based on 20% of DCN, as suggested by Staff. Accordingly, AIU's gas COSS should reflect an allocation of on-system underground storage costs based on 20% of transportation customers' aggregate DCN on the 2008 peak day.

IX. RATE DESIGN/TARIFF 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. Uncollectibles Factors

Pursuant to Section 2 of the stipulation in Docket No. 09-0399, AIU and Staff have agreed to the following regarding the determination of uncollectibles factors concerning Rider EUA and Rider GUA:

> . . . the uncollectible amounts included in rates for the periods on and after the date new rates take effect (pursuant to 09-0306 et al (Cons.)) shall be determined for each relevant customer rate class as defined in Rider EUA as follows:

a. For [delivery service ("DS")], the uncollectible amounts included in rates shall be the amount equal to the DS uncollectible component as stated in the compliance DS tariff sheets as a dollar amount per customer, per month multiplied by the number of customers. The DS uncollectible component would be included within the stated DS monthly customer charge and not appear on customer bills as a separate line item. The AIU will provide Surrebuttal Testimony on this item in the pending rate case.

The parties agreed in Docket No. 09-0399 to a similar provision with respect to Rider GUA. AIU proposes that the “average amount per customer per month” be listed in the appropriate DS tariff in the Terms and Conditions section. These amounts will be tracked within AIU’s billing system and serve as the base amount of uncollectibles included in rates, required for use in conjunction with Riders EUA and GUA. AIU’s calculations will be updated to conform to the expense level authorized by the Commission at the conclusion of the rate case. AIU and Staff are in agreement on this issue. The Commission finds the resolution of this issue appropriate and consistent with its decision in Docket No. 09-0399.

2. Miscellaneous Tariff Language Changes

With regard to the Terms and Conditions of Service section of AIU's gas and electric tariffs, Staff and AIU are in agreement on various modifications. Language revisions that AIU proposes include wording modifications and date changes in the electric “Switching Suppliers” subsection and language changes in the electric “Disconnection and Reconnection” subsection. Staff is agreeable to AIU's proposed $400 fee for customers whose service has been disconnected at the main because access to the meter was blocked. Staff also supports AIU's proposal to eliminate the references to GDS-6 in AmerenCILCO's gas tariffs if the Commission approves the elimination of GDS-6 for AmerenCILCO.

Concerning AIU's Standards and Qualifications for Electric Service, AIU and Staff are in agreement on AIU's proposed language changes to paragraph 4(B), which imposes a $170 fee per meter read. Effectively, this section was amended to include a provision to require non-residential customers to provide a means for remote meter interrogation or to require a $170 meter reading fee when AIU’s personnel do not have free access to the meter. Staff also recommends approval of AIU's proposed word additions/deletions and page updates in the Index subsection of the tariffs, AIU's proposed elimination of certain sentences and phrases in the Service Extension paragraph including ones exclusive to Ameren IP, AIU's proposed language additions and deletions to the Interval Metering subsection paragraph, and AIU's proposed language revisions in section C of Standards and Qualifications for Gas Service.

Regarding the DS-2, DS-3, and DS-4 tariffs, AIU proposes language changes to 4th Revised Sheet No.12.002 where the wording was changed to clarify that AIU’s personnel could install unmetered services without first receiving a request from customers to do so. In 7th Revised Sheet No. 13, 6th Revised Sheet No. 13.001, 6th Revised Sheet No. 13.002, 7th Revised Sheet No.14, and 6th Revised Sheet No. 14.001, AIU proposes minor language and sentence changes to the last two paragraphs. Staff recommends approval of the proposed language changes because it improves clarity across AIU's tariffs without changing the substance of the current tariff language.

In the context of Rate DS-5, since some light fixtures are no longer available, AIU proposes language modifications to 4th Revised Sheet No.12.002. Staff accepts AIU's proposed modifications.

With regard to the Miscellaneous Fees and Charges Section of its tariffs, AIU proposes changes in 2nd Revised Sheet No. 35.001. Staff agrees that the proposed changes add clarity and helpful directional information. Staff also accepts the establishment of a $170 non-scheduled meter read for customers in the GDS-4 and GDS-7 rate classes.

The Commission finds all of the miscellaneous changes described in this subsection reasonable and accepts them for inclusion in AIU's tariffs.

B. Resolved Gas Issues

1. Rate Capping Mechanism

AIU's current gas rates generate different rates of return for each rate class. One of AIU's rate design goals in these proceedings is to move each of the utilities' rate classes closer to its revenue requirement by assuming an equalized revenue requirement for each rate class within each utility. An equalized class revenue requirement would be those revenue levels required for each rate class if they were to eliminate all inter-class subsidization and produce exactly the same ROR as the overall level for each utility.

AIU, however, determined that adopting an equalized ROR level for each rate class would result in rate increases that in many instances would be so great as to result in rate shock. AIU, therefore, proposes to limit the rate increase for each rate class to a specified percentage over present rates to avoid these adverse bill impacts. If a class rate increase is limited by the rate capping mechanism, then the amount of that rate class' revenue requirement that is above the cap would be recovered from the rate classes that have not reached the cap. AIU proposes a 20% cap for AmerenIP customers and a 30% cap for AmerenCILCO and AmerenCIPS customers. The higher increase for AmerenCILCO and AmerenCIPS addresses a much larger difference in ROR and revenue deficiency levels for certain rate classes.

Staff agrees with AIU's proposed gas rate capping mechanism and recommends that the Commission approve it. Staff believes that AIU considered bill impacts and notes that while some inter-class subsidies will be necessary, those subsidies will lessen the impact of the rate increase for many AIU customers. According to Staff, AIU's proposed rate capping mechanism mitigates the concerns associated with adopting the full cost of service results and the prospect of unfavorable rate impacts that could otherwise result for some rate classes, especially due to the reclassification of rate class definitions for AmerenCILCO and AmerenCIPS. Staff also observes that the rate capping mechanism levels the distribution of the increase and spreads the proposed interclass subsidy over all other rate classes.

No other party commented on AIU's proposal. The Commission finds AIU's proposed rate capping mechanism reasonable and approves it.

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

AIU proposes a gas rate design using the cost of service based on each of the utility's revenue requirements. Once revenue targets were established for each of the rate classes, AIU relates that the rate design process was guided by three general principles moving rates towards reasonable customer impacts: (1) considering the rate capping mechanism described above; (2) eliminating inconsistencies between the three utilities' rate designs; and (3) emphasizing the 80%/20% fixed/variable thresholds authorized by the Commission for GDS-1 and GDS-2 rates in AIU's last rate cases.

Staff agrees with and recommends approval of AIU's overall proposed rate design. Staff believes that AIU properly considered bill impacts and the Commission's directives from the last rate order. To account for the difference between AIU's revenue requirement and Staff's revenue requirement, Staff proposes to scale AIU's proposed rates by the ratio of Staff's revenue requirement for each utility. This method does not alter AIU's general rate design. Instead, it simply increases or decreases the rates in proportion to the change in the revenue requirement.

In the event the Commission determines a different revenue requirement, AIU and Staff agree that use of Staff's scaling method is appropriate. No other party addressed this issue. The Commission finds AIU's overall rate design reasonable and directs that Staff's scaling proposal be used to reconcile the approved revenue requirement with the adopted rate design.

3. Interval Meter Data Access Fees

AIU no longer needs real-time data connections to its GDS-2 and GDS-3 customer meters. Because many of these customers have expressed a desire to maintain access to daily usage information, AIU proposes an optional Daily Usage Information Service with a data access fee that would reflect the cost of modifying the existing metering to make it capable of transmitting the daily meter information to AIU. AIU estimates that the installation of a modem and associated equipment necessary to provide this optional service would result in an upfront, one-time charge of either $1,944 (if an Electronic Pressure Corrector – Pulse Accumulator is required) or $812.25 (if no

Electronic Pressure Corrector – Pulse Accumulator is required). AIU proposes a $5.00 monthly service charge for this optional service. AIU proposes and Staff accepts the following new tariff language to implement the updated installation charge:

> If Customer elects such service, the Company may be required to install a remote monitoring device to provide daily usage information to Customer. If Company is required to install a remote monitoring device in order for Customer to receive Daily Usage Information Service, Customer will be required to pay Company for the cost of equipment and installation, prior to receiving service, as follows.
>
> $1944.00, for each meter where installation of a pulse accumulator is required.
>
> $812.25 for each meter where installation of only a modem is required.

GFA also approves of this provision and states that it supports making the service available as an option at a fee that recovers actual costs. No other party addressed this issue. The Commission finds the proposal reasonable and approves its inclusion in AIU's tariffs.

4. Calculation of "Highest Average Daily Use"

AIU proposes to determine the eligibility for a number of rate classes based on the customers "highest average daily usage" ("HADU"). AIU proposes to determine the HADU by dividing the customer's total usage in a billing period by the number of days in that billing period. GFA agrees with this method. No other party commented on the calculation method. The Commission accepts the proposed method for calculating a customer's HADU for determining a customer's rate eligibility.

5. Rider T - Gas Transportation Service

a. NAESB Intraday Nomination Cycles

The North American Energy Standards Board ("NAESB") is a non-profit industry forum created to develop uniform business practices intended to create a seamless marketplace for wholesale and retail natural gas and electricity. NAESB has developed gas industry standards on many matters for improved functionality in the gas industry between pipelines, LDCs, third party suppliers, and other industry participants. Among the standards developed by the NAESB is one which calls for four nomination cycles. A "nomination" is how transportation customers schedule gas deliveries from a pipeline onto a LDC's system.

AIU initially proposed to retain its existing two nomination deadlines for transportation customers. Currently, AIU permits transportation customers to submit nominations at 11:30 a.m. and 4:00 p.m. to identify the gas to be delivered on the next gas day. Staff and CNE-Gas, on the other hand, proposed that AIU permit transportation customers to submit nominations based on NAESB's Intraday 1 and Intraday 2 nomination schedules. After discussing the issue amongst themselves, AIU, Staff, and CNE-Gas now agree that new tariff language implementing a single "same day" nomination schedule at 7:30 a.m. (rather than the NAESB Intraday 1 and Intraday 2 schedules) is a reasonable solution. The parties agree that the same day nomination reasonably balances AIU's interest in maintaining system reliability with the customers' interest in additional flexibility. AIU's tariffs require the utilities to use their best efforts to accommodate any other off-cycle nominations. AIU, however, currently does not provide transportation customers with the firm right to submit intraday nomination changes. The new tariff language implementing a new "Same-Day" nomination as part of the Nomination of Customer-Owned Gas section of each of the Rider-T tariffs reads as follows:

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

No other party addressed the issue of nomination deadlines. The Commission finds the resolution of this issue and the new tariff language reasonable and approves of the inclusion of the language in AIU's tariffs.

b. Notice for Operational Flow Orders and Critical Days

When a gas utility needs to curtail gas to customers, it may declare an OFO or CD. AIU initially proposed to retain the existing tariff language regarding prior notice of OFOs and CDs. Staff proposed that AIU make a good faith effort to give a 24-hour notice of OFOs or CDs. CNE-Gas proposed that AIU provide notice as far in advance as possible--normally not less than two hours, unless conditions warrant immediate implementation of the OFO or CD. In response to the concerns expressed by Staff and CNE-Gas, AIU agrees to provide advance notice of an OFO or CD as far in advance as reasonably possible. Moreover, AIU agrees to submit a report to the Commission (specifically, the Director of the Energy Division) within two business days if it does not provide a 24-hour notice. In particular, AIU states that it is willing adopt the following tariff language as part of the Rider T section titled System Integrity Protection:

> The Company shall provide notice of a Critical Day and OFO as far in advance as reasonably possible, normally not less than two hours, unless the Company believes conditions warrant immediate implementation of the Critical Day or OFO. If the Company issues a Critical Day or OFO

notice within 24 hours of the Critical Day or OFO taking effect, the Company will report to the Commission indicating why customer notice of less than 24 hours was necessary.

Staff and CNE-Gas support adoption of the proposed addition to Rider T. The Commission finds the proposed language reasonable and approves of the inclusion of the language in AIU's tariffs.

6. Large Customer Rate within GDS-4 Rate Class

Of the three gas utilities, only AmerenCILCO currently has a rate class for customers with annual usage in excess of 2,000,000 therms--the GDS-6 rate class. AmerenCIPS and AmerenIP customers with usage in excess of 2,000,000 therms are covered under the GDS-4 rate class. AIU proposes to eliminate AmerenCILCO's GDS-6 rate class as a stand-alone tariff and transfer the GDS-6 customers to AmerenCILCO's GDS-4 rate class. AIU then proposes to modify only AmerenCILCO's GDS-4 tariff to mitigate any adverse rate impact for former GDS-6 customers. Because neither AmerenCIPS nor AmerenIP have a GDS-6 rate class, AIU states that introducing large customer provisions to the AmerenCIPS and AmerenIP GDS-4 tariffs is unwarranted and would introduce an unnecessary level of complexity. AIU proposes to include a price step in AmerenCILCO's GDS-4 tariff simply to promote stability for the existing customers served under AmerenCILCO's GDS-6 tariff. AIU states further that AmerenCILCO's special provisions for large customers are one of the few instances where other factors take precedence over the desire for tariff uniformity.

AIU agrees with Staff's recommendation that, in the time between these rate cases and the next rate cases, AIU should assemble data associated with AmerenCIPS' and AmerenIP's GDS-4 customers with annual consumption over 2,000,000 therms to evaluate whether AmerenIP and AmerenCIPS should implement special GDS-4 rate provisions for those customers. While AIU is only proposing these tariff provisions for AmerenCILCO in these rate cases, AIU agrees that assembling this data may help provide support to AIU's gas tariff design in the next rate case.

Staff recommends approval of (1) AIU's proposal to eliminate AmerenCILCO's GDS-6 tariff as a stand-alone rate class and (2) the special large customer provisions under AmerenCILCO's GDS-4 rates. Staff does not seek the immediate adoption of identical terms for larger AmerenCIPS and AmerenIP GDS-4 customers because it recognizes that AIU has not assembled the necessary data to implement this change. By its next rate case, Staff believes that AIU should have evaluated the relevant data to determine whether a similar rate design is appropriate for large customers of AmerenCIPS and AmerenIP with usage of more than 2,000,000 therms annually.

The Commission understands no other party voiced a position on this matter and that AIU and Staff are in agreement. The Commission finds AIU's proposal to eliminate AmerenCILCO's GDS-6 tariff reasonable, as well as its proposal to modify AmerenCILCO's GDS-4 tariff to mitigate any adverse rate impact for former GDS-6 customers. The Commission also considers it appropriate for AIU to assemble data associated with AmerenCIPS' and AmerenIP's GDS-4 customers with annual consumption over 2,000,000 therms to evaluate whether AmerenIP and AmerenCIPS should implement special GDS-4 rate provisions for those customers. The Commission expects the results of such efforts to be presented in AIU's next rate case.

C. Resolved Electric Issues

1. Rider PER - Purchased Electricity Recovery

AIU proposes to modify Rider PER - Purchased Electricity Recovery ("Rider PER") so that it identifies this docket as establishing Basic Generation Service ("BGS") base prices, replacing a reference to the rate redesign case, Docket No. 07-0165. AIU states that this change is necessary to the extent the Commission accepts AIU's proposal to adjust BGS-1 and BGS-2 prices in this proceeding. In response, Staff suggests one minor change to Sheet No. 31.008, which AIU accepts. The Commission finds the agreed to language reasonable and adopts it.

2. Supply Cost Adjustments for Rider PER

A Supply Cost Adjustment ("SCA") is applied to customers billed under Rider PER for recovery of certain costs for procurement (Supply Procurement Adjustment), working capital (CWC Adjustment), and uncollectibles (Uncollectibles Adjustment). AIU describes a detailed plan for recovering the costs related to its power supply through the SCA. In response, Staff proposed one change to the Supply Procurement Adjustment and two changes to the Uncollectibles Adjustment. Those changes are: (1) a corrected amount for costs associated with the procurement of power; (2) the uncollectibles factors for recovery under Rider PER should be consistent with the uncollectibles to be recovered through base rates; and (3) the allocation of write-offs between gas and electric service for combination customers should be based on the relative revenues for each type of service. AIU agrees with Staff's recommendation that $1,278,100 should be approved as the Supply Procurement Adjustment component of Rider PER. Staff also accepts AIU's counter proposal for the uncollectibles percentages based on net write-offs as a percentage of revenues, using calendar years 2007 and 2008 and year-to-date September 2009. Staff is no longer advocating its third recommendation. AIU and Staff are now in agreement on these revisions. The Commission finds the proposal reasonable and adopts it.

3. Rider RDC - Reserve Distribution Capacity

AIU proposes a change to Rider RDC - Reserve Distribution Capacity to ensure that the phrases "Demand" and "Billing Demand" are not interchangeable terms. Presently, "Demand" and "Billing Demand" share the same definition, but the term "Billing Demand" is adjusted within both the DS-3 and DS-4 tariffs to carry a different meaning. In response, Staff suggests that the term "billing demand" not be capitalized.

AIU has agreed to this revision. The Commission finds the revisions reasonable and adopts it.

4. Rider QF - Qualifying Facility

AIU proposes to eliminate a provision in Rider QF - Qualifying Facility ("Rider QF") that allows it to refuse to accept output from a qualifying facility when the purchase of the output does not permit it to avoid costs. AIU currently uses energy purchases to offset power procured on behalf of fixed-price customers. Qualifying facility purchases usually influence the quantity of energy AIU buys and sells through the MISO-administered markets as AIU balances its fixed price energy portfolio. As long as there is a MISO-administered market, AIU does not anticipate a situation where the purchase of output from a customer's qualifying facility would permit AIU to avoid costs. As such, AIU proposes to eliminate this section. No party opposes this revision. The Commission finds the proposed change reasonable and approves it.

5. Rider HMAC - Hazardous Materials Adjustment Clause

Costs related to hazardous materials claims are recovered under AIU's Rider HMAC - Hazardous Materials Adjustment Clause ("Rider HMAC"). The HMAC BASE Amount, as defined in Rider HMAC, is the amount of HMAC costs reflected in the test year in the most recent electric rate case Commission order. This amount is needed to determine the amount to be withdrawn or deposited annually into the HMAC Cost Fund. Staff observes that the BASE Amount included in AmerenIP's revenue requirement is $411,889 and requests that the final order in this proceeding clearly indicate this BASE Amount for ease in applying Rider HMAC in future periods. AIU agrees that the HMAC BASE Amount included in AmerenIP's revenue requirement is $411,899. The Commission concurs.

6. DS-4 Reactive Demand Charge

Staff recommends that AIU modify language in the Standards and Qualifications for Electric Service section of each utility's tariffs. Staff believes that the existing language could give the false impression to Rate DS-4 customers that they can avoid monthly reactive demand charges if they maintain a power factor within the range 95% lagging to 95% leading. In actuality, based upon AIU's Rate DS-4 tariff, Rate DS-4 customers with a supply voltage below 100 kV can not, in practical terms, avoid a monthly reactive demand charge. In response to Staff's concerns, AIU proposes to add an additional sentence to this section of its tariffs that better explains reactive demand charges for Rate DS-4 customers. Staff finds AIU's proposed language adequate. The Commission finds the modification reasonable and approves its inclusion in AIU's tariffs.

7. Tail Block Variable Charges

While AIU initially proposed a 10% increase in the total variable charges for tail block BGS-1 and BGS-2 rates, it now agrees with Staff and urges the Commission to approve an increase to the total variable charges for tail block BGS-1 rates of 13%. AIU and Staff continue to support a 10% increase in the total variable charges for tail block BGS-2 rates. As Staff noted in its Initial Brief, without this increase in the BGS-1 rates, AIU incurs a shortfall of approximately 4¢ for each kWh sold to AmerenCIPS-ME and AmerenIP space heating customers, as well as a deficit of between 2 and 3¢ for each kWh sold to AmerenCIPS space heating customers. AIU adds that this increased charge unburdens the remaining bundled customers who would otherwise have to make up for this shortfall. AIU states that this increase is necessary to assist in reducing the amount of subsidy inherent in the present BGS-1 rates for non-summer use over 800 kWh.

Staff and AIU also agree that the annual cost effect of increasing the tail block variable charge by 13% for DS/BGS-1 customers would be minimal. The incremental increase for customers using 18,000 kWh per year would be about $1.50 at AmerenIP, $3.50 at AmerenCIPS, $1.00 at AmerenCIPS-ME, and $4.50 at AmerenCILCO. Similarly, a space-heat customer using 26,000 kWh per year would experience annual increases of about $7.00 at AmerenIP, $10.00 at AmerenCIPS, $5.30 at AmerenCIPS-ME, and $11.75 at AmerenCILCO.

The Commission concurs with AIU and Staff that the tail block variable charge for DS/BGS-1 customers should increase by 13%. The customer impacts of this change are minimal. Raising the tail block rate is also a step in the right direction toward eliminating a subsidy. The Commission also finds the proposal to raise the tail block rate for DS/BGS-2 customers by 10% reasonable. The AIU and Staff agreement on the issue of tail block rates for BGS-1 and BGS-2 rates is adopted.

8. Cost Based Seasonal Rate

In support of its argument for seasonal distribution rates, GFA states that transformers for DS-3 and DS-4 customers are often sized to serve only one customer, for which costs are recovered via a Transformation Charge specific to that customer. Similarly, meters and service are specific to one customer and these costs are recovered in the Customer Charge and Meter charges. As AIU confirms in response to data request PL4.02, however, GFA asserts that the rest of the electric distribution line and substation system capacities are built to carry the aggregate peak coincidental load of all customers served from each part of the system. GFA understands that summer month coincident peaks are typically higher on the AIU system than are winter month coincident peaks. Because the coincidental system peaks on the AIU system vary by season, GFA concludes that AIU's distribution system cost of service varies by season. Therefore, GFA maintains that AIU should price its distribution delivery service charges, excluding monthly fixed charges, higher during the summer and lower during the non-summer months. As in AIU's last rate case, GFA simply requests that AIU begin collecting the necessary data to conduct analysis of prospective seasonally cost based rates for the DS-2, DS-3, and DS-4 classes with regard to costs of substations and primary lines within the Distribution Delivery Charge.

AIU does not believe that implementation of a seasonal Distribution Delivery Charge is as simple as GFA suggests. GFA reasons that since as a group, the non-residential classes tend to peak in the summer, additional costs, and thus, greater rates, should be assigned to the summer period. AIU points out, however, that substations and primary lines are designed to serve the maximum demand expected on the facilities, regardless of the season. AIU adds that circuits serving customers with large grain drying loads can, and do, peak in the fall season. To provide this subclass with a lower rate in the non-summer season, AIU continues, would send an incorrect price signal to these customers. Instead, AIU asserts that a cost-based seasonal rate for this subclass would likely have greater demand charges in the fall, which would encourage customers to be as efficient as possible in managing their peak demands, since it is their demands that contribute the most to the need for substation and primary line capacity.

Additionally, because the DS-2 class already contains a seasonally-differentiated price, and the non-summer delivery charge is lower than the summer charge, AIU contends that seasonal pricing is unnecessary with respect to that class. AIU goes on to state that one can not consider seasonal rates without examining the price incentives and the possible cost consequences those price signals would have on distribution system costs. AIU suggests that a lower non-summer rate for certain customers (here, grain dryers) would signal that delivery service to them is cheaper, providing customers an incentive to use more, even though the delivery system with large grain drying load may already be constrained at the time of the fall peak.

AIU states further that DS-4 and large DS-3 customers connected at the primary voltage supply level can be large enough to drive local circuit peaks. AIU also indicates that examining seasonal rates for non-residential customers requires attention to circuit level details rather than aggregate demands of all customers -- a highly manual process. Nevertheless, AIU acknowledges that examining a sample of circuits serving DS-3 and DS-4 customers may help bring additional clarity to the debate. The study would also measure such customers' revenue contribution relative to their cost responsibility -- the issue GFA wishes AIU to examine. AIU is interested in proper cost allocation and pricing, and thus does not object to further study in the next rate case.

The Commission understands that GFA and AIU are in agreement that this issue will be addressed in AIU's next electric rate proceeding. The Commission also understands that prior to that time AIU will study a sample of circuits serving DS-3 and DS-4 customers to evaluate such customers' revenue contribution relative to their cost responsibility. The Commission believes that doing so is reasonable and directs AIU to conduct the described study and provide the results with its next electric rate case filing.

D. Contested Gas Issues

1. Availability Tariff Provisions

a. AIU Position

Pursuant to the Commission's direction in its last rate cases, AIU proposes a number of changes to its tariffs in these rate cases with the goal of achieving uniformity in tariff provisions. AmerenCILCO, AmerenCIPS, and AmerenIP all have similar non-residential rate classes GDS-2, GDS-3, and GDS-4. The availability (or eligibility) provisions of those rate classes, however, differ from company to company. In considering an appropriate availability threshold, AIU sought to use the existing availability provisions and/or methodologies of one of its companies. The AmerenIP tariff currently assigns customers to rate classes GDS-2, GDS-3, and GDS-4 based on each customer's actual HADU. AIU observes that the AmerenIP availability provisions provide customers with an immediate and definitive classification method using easily accessible information. On the other hand, the current AmerenCILCO and AmerenCIPS availability criterion rely upon methods of meter size, calculation of connected gas load, and definition of "general" use. Because AIU believes that usage-based availability provisions are the easiest for customers to understand and its staff to administer, AIU proposes moving AmerenCILCO and AmerenCIPS to the AmerenIP availability methodology.

AIU analyzed the major cost differences in the meters that are currently used to serve the various customer groups in order to determine whether the usage thresholds should be adjusted from the current AmerenIP levels. AIU reports that the analysis indicated that the existing AmerenIP usage thresholds follow the major cost differences in the meters. AIU conducted the COSS and individual customer impact studies on customers of all three utilities using the HADU thresholds proposed in its tariffs. The result of this change for most gas customers will be some migration from GDS-4 to GDS-3 or from GDS-3 to GDS-2. AIU states that customers moving down a rate class as a result of this change should not face detrimental bill impacts.

AIU notes that GFA supports its goal of achieving uniformity of in its tariff provisions. But GFA objects to two elements of AIU's availability proposal. First, GFA argues that a customer's HADU should be based only on the customer's usage in the months of December through March. Second, GFAI argues that the cutoff between GDS-3 and GDS-4 should be based on the annual usage criteria currently employed at AmerenCILCO rather than HADU. The following table summarizes the key differences between AIU's proposal and GFA's proposal:

	AIU's Proposed Availability Provision	GFA's Proposed Availability Provision
GDS-2	Upper Limit: HADU < 200 therms	Upper Limit: HADU < 200 therms – measured only in the billing months of December through March
GDS-3	Lower Limit: HADU ≥ 200 therms Upper Limit: HADU < 1000 therms	Lower limit: HADU ≥ 200 therms – measured only in the billing months of December through March Upper Limit: annual usage of 250,000 therms. Alt. Upper Limit: HADU < 1000 therms – measured only in the billing months of December through March
GDS-4	Lower Limit: HADU ≥ 1000 therms	Lower Limit: annual usage of 250,000 therms. Alt. Lower Limit: HADU ≥ 1000 therms – measured only in the billing months of December through March

With regard to GFA's first complaint, AIU understands why GFA would pursue rate structures that are advantageous to its membership – a group whose primary gas usage typically occurs outside the months of December through March. AIU understands that a typical grain drier will use about 80% of its annual natural gas volume during harvest, which is about a two month period in the fall. AIU suggests that the intent of GFA's proposal is to address the seasonal usage of its membership. But according to AIU, its tariffs already recognize the different impacts that seasonal customers have on fixed and variable costs, and reflect that recognition in the billing components and associated charges in the GDS-5 rate class. The GDS-5 rate class enables customers who use gas only on days when the average temperature is forecasted to be above 25 degrees Fahrenheit to avoid paying a demand charge. Since the December through March timeframe is the time of year when it is most likely that the temperature will be 25 or lower, AIU asserts that the GDS-5 rate accomplishes GFA's goal. AIU maintains that using GFA's proposed four-month calculation period to determine rate availability would simply result in an inequitable assignment of fixed costs. Moreover, AIU states that adding a seasonality component to the other gas delivery service tariffs is unsupported, redundant, and inconsistent with the goal of uniformity.

AIU strongly disagrees with GFA's contention that there is little difference between its proposal and AIU's proposed availability criterion. By grossly understating the impact that its proposal will have on customers, AIU argues that GFA fails to recognize that its proposed modification is likely to lead to an inequitable assignment of costs among customer classes. In fact, AIU continues, under the GFA proposal, it is very likely that many of the seasonal customers would move to a lower tariff class than would be justified, based on the investment and equipment needed to serve their loads. AIU insists that GFA's position for restricting HADU measurement to the December through March timeframe ignores that the bulk of the costs to build, operate, and maintain gas delivery systems are fixed charges which do not vary based on the time of year that the usage occurs, and that all users of the system should pay an equitable share of those costs. According to AIU, GFA's proposal would result in customers using the system during non-peak periods paying nothing towards the fixed costs of operating the system. AIU asserts that the Commission previously recognized the need for all users of the system to pay their share of the fixed costs, regardless of the amount of gas they use or the time of year when the usage occurs, by placing 80% of fixed cost recovery into the Customer Charge for GDS-1 and GDS-2 customers.

Furthermore, AIU maintains that GFA's proposal is unworkable because customers could simultaneously qualify for the GDS-2 and GDS-3 or GDS-4 rate classes. As an example, AIU states that if a grain-drying customer had an average daily use of 1,500 therms during the September through November harvest season, and minimal usage for the rest of the year, under GFA's proposal, the customer's annual usage could exceed 250,000 therms and result in the customer being assigned to GDS-4. The customer would then be required to implement daily balancing and install a phone line, and AIU would need to install interval metering to record this usage appropriately. The same customer, however, plausibly would have a HADU of less than 200 therms per day during the non-harvest December through March timeframe, which would result in the customer being assigned to GDS-2 and able to balance monthly, with no need for a phone line or extensive metering. AIU does not mean to suggest that the customer would change between rates more than once a year. AIU simply means that the GDS-2, GDS-3, and GDS-4 rates are not intended to be a menu of options from which customers can choose once each year. AIU states that this would not only cause confusion for customers, but also add ambiguity for rate administration, which would result in financial uncertainty for the recovery of a utility's approved revenue requirements. AIU adds that tariff applicability provisions that allow a customer to select between standard GDS rate classes without any meaningful change in usage patterns can also be detrimental to other customers over the long run, as rates are established in future rate cases.

Despite proposing entirely new availability provisions for all three of the companies, AIU points out that GFA does not provide any rate design, cost allocation, or bill impact analysis. AIU contends that GFA simply desires a change that it thinks will benefit its membership without any consideration of the potential impact on other customers. In contrast, AIU asserts that it has prepared and presented a unified, consistent rate design plan supported by the appropriate analysis and consideration. AIU also contends that GFA simply rehashes arguments from the last AIU rate cases, which the Commission rejected.

Regarding GFA's second complaint concerning the cutoff for service under the GDS-3 and GDS-4 rate classes, AIU asserts that GFA provides no analysis supporting its proposal to use a maximum annual usage of 250,000 therms as the cutoff. Instead, AIU notes that GFA supports its availability proposal only with the claim that the 250,000-therm maximum annual usage limit is based on the existing lower limit of AmerenCILCO's GDS-4 rate class. AIU contends that GFA does not explain why it prefers the AmerenCILCO cutoff to the AmerenIP cutoff. To determine availability for GDS-3 using the GFA methodology, AIU would use both a daily average calculation based on a four-month window (to determine the lower limit), as well as a total usage threshold that considers 12 months of usage (to determine the higher limit). In contrast, AIU states that its proposal is easier for customers to understand, and for AIU to administer, because it relies only on a single calculation of the customer's HADU to determine both the upper and lower limits. AIU finds it notable that GFA supports using a 1,000-therm HADU cutoff (measured from December through March) between GDS-3 and GDS-4 as an alternative.

b. GFA Position

GFA supports consistent eligibility requirements and tariff structures among the three companies. GFA, however, questions whether AIU has chosen the most appropriate eligibility requirements from among all AIU current rates. While GFA agrees with using a 200 therm or less HADU eligibility requirement for the GDS-2 rate class, GFA recommends that the HADU be tested only for usage during the billing months of December through March, when system daily maximum usage is greatest. GFA denies that its proposal would result in customers potentially simultaneously qualifying for the GDS-2 and GDS-3 or GDS-4 rate classes, because of differing monthly usage throughout the year. GFA, like AIU, proposes only one annual eligibility test and supports the proposed AIU tariff provision which specifically prohibits customers from switching between rates throughout the year. The GDS-2, GDS-3, and GDS-4 tariffs each contain similar language to prevent switching under the heading Delivery Service Rate Reassignment. The GDS-2 tariff states: "Once the Customer has been assigned to Rate GDS-3 or GDS-4, the Customer will not be eligible to receive service under Rate GDS-2 for a minimum of 12 monthly billing periods following such reassignment." The GDS-3 and GDS-4 tariffs have comparable language. GFA concludes that its proposal would therefore give customers a choice only once annually, but each choice carries a year long commitment.

Regarding the next rate class, GFA observes that both its and AIU's GDS-3 recommendations match up low-end GDS-3 eligibility to the high-end eligibility for GDS-2 (with the exception of GFA's December through March measurement period). GFA's high-end cutoff for the GDS-3 rate class, however, differs. GFA notes that the current AmerenCILCO and AmerenCIPS GDS-3 rates have no maximum to qualify for the rate. The current AmerenCIPS GDS-4 rate has no minimum use requirement and the current AmerenCILCO GDS-4 has a minimum annual use requirement of 250,000 therms. To be more consistent with current eligibility requirements of all three companies' GDS-3 and GDS-4 rates, and to have the high-end requirement for GDS-3 match up with the current low-end requirement of AmerenCILCO's GDS-4 rate, GFA recommends matching all three companies' GDS-3 high-end eligibility to AmerenCILCO's simple and straightforward current minimum GDS-4 requirement of a maximum annual use of 250,000 therms. Alternatively, GFA recommends AmerenIP's current GDS-3 requirement of HADU equal to or greater than 200 therms per day and less than 1,000 therms per day, except that the annual eligibility test be made on customer usage only for the peak system usage billing months of December through March.

GFA disputes the appropriateness of the cutoff between the GDS-3 and GDS-4 rate classes as well. Despite AIU's claim that it analyzed appropriate cutoff points, GFA in essence suggests that AIU arbitrarily chose to apply the AmerenIP cutoff points. Contrary to AIU's use of the AmerenIP cutoff points, GFA recommends an annual minimum use of 250,000 therms to be the eligibility threshold for the GDS-4 rate schedule for all three companies. Alternatively, GFA recommends AmerenIP's current GDS-4 requirement of HADU equal to or greater than 1,000 therms per day, except with the annual eligibility test being applicable to customer usage only for the billing months of December through March. GFA believes that its proposal would promote system reliability by discouraging system utilization during peak or near peak load periods, and greater system utilization during non-peak periods.

GFA denies that its proposal would result in some customers using the gas distribution system during off-peak periods paying nothing towards the fixed costs of operating the system. GFA suggests that AIU could establish a minimum billing demand, similar to used in its electric tariff. AIU's math regarding its hypothetical customer's usage is also suspect, which GFA implies calls into question the rest of AIU's analysis.

c. Staff Position

Staff does not object to AIU's proposal to apply the AmerenIP usage-based availability criterion to the GDS-2, GDS-3, and GDS-4 rate classes of AmerenCILCO and AmerenCIPS. Staff states that the modifications provide more uniformity in the gas rate class structures as well as uniformity with the AIU electric tariffs. Staff believes that the resulting uniformity may also avoid potential confusion. Regarding the bill impacts of this change, Staff finds that the proposed rate class definition changes and resulting reclassifications would result in comparable increases for the majority of AIU customers.

d. Commission Conclusion

The Commission appreciates GFA's concerns, but at this time is not confident that implementation of its proposal is as straightforward as GFA suggests. Specifically, the Commission is concerned that GFA has not provided any rate design, cost allocation, or bill impact analysis in support of its position. AIU's proposal to make the gas rate classes more uniform among the three companies is likely to raise questions for some customers. To risk further complicating any explanation with potential problems that may arise from implementation of GFA's proposal is not in the customer's best interest. While the Commission may entertain different availability criteria in the future, for purposes of this rate case, the Commission finds AIU's proposed revisions regarding non-residential rate classes GDS-2, GDS-3, and GDS-4 for each company reasonable and authorizes the implementation of such.

2. Seasonal Prices for all GDS Rates

a. GFA Position

GFA understands that AIU’s gas distribution system is designed to accommodate peak usage, which occurs during winter months. Therefore, GFA recommends that all delivery charges, excluding monthly fixed charges, reflect seasonal prices. Such a proposal benefits typical grain dryers, which use about 80% of their annual natural gas volume during harvest, which is about a two month period. Thus, a typical size grain dryer can expect to use approximately 40% of annual usage in each of two harvest months and approximately 2% of annual usage in each of the other ten months.

With regard to seasonal rates and the GDS-2 tariff, GFA states that AIU seems to recognize the value of encouraging use during the non-winter months of April through November, but fails to recognize that the GDS-5 tariff does not send appropriate price signals to customers small enough that they qualify for service under the GDS-2 tariff. GFA states that a typical grain dryer of the GDS-2 size would never be expected to utilize the GDS-5 tariff because of the proposed high monthly fixed charges. Using the typical usage profile, GFA observes that a GDS-2 grain dryer using 15,000 therms annually under the proposed AmerenIP GDS-2 rate will pay $1,710.00 annually in Distribution Delivery Charges. Because the GDS-5 rate has relatively high fixed monthly charges and is designed for larger customers, however, GFA points out that the proposed GDS-5 rate annual charge for this same GDS-2 grain dryer would be $5,377.50. GFA states that a small GDS-2 grain dryer would not be expected to pay over three times the GDS-2 rate delivery charges to avail itself of the off-peak provisions of the GDS-5 rate like larger GDS-3 or GDS-4 customers may do. Although the GDS-5 off-peak provisions is an excellent way to increase off-peak system utilization, GFA asserts that the proposed GDS-5 rate needs to include levels of fixed monthly charges which are comparable to the respective GDS-4, GDS-3, and GDS-2 rates. To address this concern, GFA suggests that AIU could have a second tier lower fixed charge within its GDS-5 rate for smaller off-peak customers to encourage greater utilization of its distribution system. Alternatively, GFA states that AIU could adopt GFA’s recommendation of making the availability limit of the HADU of 200 therms or less be applicable once annually for only the billing months of December through March when system daily maximum usage is greatest.

In response to AIU's assertion that it designs its gas distribution systems to carry the peak needs of its customers regardless of the time of year in which they occur, GFA argues that a more important consideration for seasonal rates than maximum annual design capacity is how price signals can maximize utilization of the system through interruptible incentives at times of peak system use. GFA appreciates that AIU has recognized the need to have price signals within the GDS-5 rate which encourage customers to interrupt when the temperature is below 25 degrees. GFA maintains, however, that AIU has provided no data to support not also having a cost-based distribution seasonal rate within its GDS-2, GDS-3, and GDS-4 rates, particularly for the GDS-2 small customer rate for which the temperature-based GDS-5 rate is of no practical value.

GFA states further that AIU has missed the fundamental point that the fixed costs of building a distribution system are correlated with the capacity of the system. That is, the system capacity is determined by its pressure and pipe size. GFA avers that customers who are willing to be interrupted or do not use the system at time of system peak loads of other firm customers certainly reduce overall system average fixed costs. GFA does not propose the extreme referred to by AIU that customers using the system during non-peak periods pay nothing towards fixed costs. GFA, however, does recommend that not just larger interruptible or seasonal-use GDS-3 and GDS-4 customers have access to a seasonal-based or temperature-based tariff such as the optional GDS-5 rate, but that GDS-2 customers also have a similar option, either within the GDS-2 tariff or feasible access to the GDS-5 tariff.

GFA disagrees with AIU's argument that typical GDS-2 size customers do not affect reliability of the distribution system during periods when space heating load occurs, but that GDS-3 and GDS-4 customers can have a profound negative impact on system reliability during periods when peaks occur. GFA asserts that the aggregate load of a group of GDS-2 customers can equal or exceed the load of a GDS-3 or GDS-4 customer. GFA's position is that prices in tariffs for GDS-2 size customers should provide similar incentives as tariffs for GDS-3 and GDS-4 size customers: to utilize the system during non-peak load periods and not to utilize the system when heating loads are at or near peak. That can be accomplished, GFA concludes, through either making the GDS-5 tariff feasible for GDS-2 sized customers and/or by implementing seasonal prices within the GDS-2 tariff.

b. AIU Position

AIU contends that GFA's position is based on its misplaced belief that AIU's distribution system is only designed to carry the utilities' overall winter peak usage. In fact, AIU states, it designs its systems to support the peak needs of its customers, regardless of the time of year in which they occur. If the sole design criteria were based on system peak usage during the winter months, AIU contends that off-peak gas users (like GFA's members) would have insufficiently sized facilities to support their operations, since their winter gas usage is either minimal or non-existent. AIU argues that GFA's recommendation is inconsistent with the principles of system design and the recovery of system investment costs.

AIU asserts that the GDS-5 tariff is the tariff most applicable to GFA's members. The GDS-5 tariff reflects the different impacts seasonal-use customers have on costs associated with gas delivery. According to AIU, the purpose of the GDS-5 tariff is to promote system reliability by discouraging gas use by individual customers whose operation on days when space heating demands increase would cause reliability issues. AIU states that usage by GDS-3 and GDS-4 customers during periods when peak space heating load occurs can have a profoundly negative impact on system reliability. As a result, AIU continues, the GDS-5 tariff is designed to provide incentives to GDS-3 and GDS-4 customers whose processes enable them to avoid operating during periods of heating loads. AIU acknowledges that GDS-2 customers might not financially benefit from selecting to be billed under the optional GDS-5 tariff, but maintains that this does not inappropriately exclude those customers from the optional GDS-5 tariff because the usage of small GDS-2 customers typically does not affect the reliability of the distribution systems that serve them when space heating load occurs. Accordingly, AIU urges the Commission to reject GFA's proposal to implement seasonal pricing provisions for all delivery charges.

AIU is also critical of GFA's proposal because it offers no detail concerning its implementation. Nor, AIU continues, does GFA offer any analysis evaluating the actual financial effects of its proposal. For these reasons alone, AIU believes that GFA's proposal should be rejected.

c. Commission Conclusion

The Commission understands that AIU's non-residential gas customers may take advantage of seasonal rates under GDS-5 at their discretion. Certainly one factor customers would consider in whether to do so is whether it would be financially practical. The essence of GFA's concerns appears to be that under AIU's current tariffs, it is very unlikely that it would ever be financially practical for a GDS-2 customer to make use of GDS-5 seasonal rates. AIU does not deny this possibility, but also contends that such a seasonal rate for GDS-2 customers may not be worthwhile in terms of system reliability. AIU indicates that its primary concern with implementing a seasonal rate is that it help reduce load when peak space heating load occurs. AIU maintains that GDS-2 customers do not typically affect the reliability of the distribution systems that serve them when space heating load occurs.

The Commission understands GFA's concerns, but is not convinced that modifications concerning seasonal rates are warranted at this time. The record lacks evidence indicating that a seasonal rate for GDS-2 customers would benefit system reliability. Moreover, the record lacks evidence on the impact of GFA's proposal on rate design overall, not to mention how to even implement GFA's proposal. If GFA continues to believe that accommodations should be made for additional seasonal rates, GFA should bring specific proposals, containing tariff language and analysis, for the Commission and other parties to consider.

3. Banking under Rider T - Gas Transportation Service

Those customers who purchase their gas supply from a third party have the gas delivered by AIU under Rider T. Such customers tend to be larger customers with commercial or industrial process load. By way of contrast, sales customers are primarily residential heating load customers.

AIU provides banking service to its transportation customers. Under this service, if a transportation customer delivers more gas in a day to AIU than the customer uses for that day, then AIU will hold – or "bank" – that excess gas until it is needed by the customer. In this way, customers can bank an amount of gas equal to up to ten times its MDCQ under current tariff language. If a customer has a positive balance in its "bank" account, then the customer can call on its bank by using more gas in a day than it delivers in that day. In that situation, AIU would make up the difference by using its storage, line pack, or imports from off-system resources. The costs of providing the banking service are recovered through base rates as part of the distribution service.

a. Staff Position

Staff recommends that the Commission require AIU to work with Staff and other interested parties (1) to develop an equitable allocation process for storage assets, (2) to allow customers to select the level of banking that best suits their needs, and (3) to develop an equitable allocation of the costs of providing those services. Staff proposes that workshops be held to examine these issues. Staff further recommends that AIU be required to propose in its next rate case tariffs consistent with these goals using language agreed upon in the workshops.

To accomplish these goals, Staff believes that it is necessary to unbundle banking service. Staff defines bundling as the practice of a seller selling several services together for one price. Therefore, unbundling allows individual customers to buy only the services that they desire and at a level that best meets their needs.

Staff explains that under Rider T, banking services are bundled with distribution service and costs are allocated based on peak day deliverability. In comparison, Staff reports that Nicor, Peoples, and North Shore offer banking to their transportation customers without bundling those services with base rates. In fact, Staff continues, amongst these large utilities, only AIU prevents transportation customers from selecting a level of bank capacity that meets their individual needs. Staff adds that other utilities allocate their seasonal capacity equitably to reflect their assets. Staff recommends that AIU provide banking in a manner similar to the way Nicor, Peoples, and North Shore do.

While AIU recognizes some merit in such proposals, Staff notes that AIU has some concerns about expanding bank size. AIU has commented that expanding bank capacity could create a subsidy from sales customers to transportation customers because capacity might not be available and if it is, it would be more expensive. Although Staff supports allowing a subscribable bank, it suggests that the total capacity available should be limited to a proportional level of seasonal capacity in a manner similar to the way Nicor limits bank capacity. The size of the individual customer's allocation should be constrained as well, according to Staff. To protect against exorbitant prices for transportation customers based on off-system storage assets, Staff further recommends that the Commission order that the unbundled Rider T bank be based on on-system storage assets (like Nicor) or total system assets (like Peoples).

Regarding the size of any unbundled bank, Staff notes that in AIU's previous rate cases, the Commission found that a 10-day MDCQ bank is an appropriate size for each of the three gas utilities despite each having different storage capacity. Staff contends that each of the three companies' bank size should be related to their respective storage capacity. Staff also maintains that whatever bank size is eventually adopted, the capacity should be notably larger than tens day of MDCQ. Using the seasonal capacity allocation methods of Nicor and Peoples to show that the proportional capacity is very similar to the AIU systems, Staff calculates that AIU's total system capacities, relative to peak day needs, are comparable to the other utilities. This evidence shows that, while AIU has less capacity in an absolute sense than Nicor, Peoples, and North Shore, a similar allocation method would yield banks significantly larger than the current level. Staff points out that Peoples, which has just a single on-system storage field, and North Shore, which has no on-system storage, both offer relatively large banks when compared to AIU despite the fact that AIU has numerous on-system storage fields that provide more flexibility.

In determining the appropriate bank size for each of the three companies, Staff is also concerned about the allocation being done equitably. Staff disagrees with AIU's contention that the ten-day MDCQ banks are fair and equitable because transportation customer banks have increased significantly since the last case. Staff asserts that this change is the result of customer migration from sales to transportation service since the last rate case.

Nor does Staff find any merit in AIU's claims that (1) there is no demand for unbundling the Rider T bank, (2) it is too soon to consider changing the current tariffs, and (3) increasing bank sizes will result in an allocation away from sales customers to transportation customers. Staff states that CNE-Gas has expressed support for allocating storage assets using the methodologies the Commission approved for Nicor and Peoples, which unbundle banks from base rates, allow transportation customers to select a level of banking they need, and ties cost recovery to the selected bank level. Staff adds that IIEC, another transportation intervenor, states that its member companies would "likely" be supportive of these same issues in its responses to Staff data requests DAS 9.1-9.3. In response to AIU's claim that there is insufficient experience with the current banking provisions to support a change at this time, Staff notes that AIU is actually reducing its off-system storage capacity, which indicates to Staff that AIU has not had a difficult time supplying the increased bank capacity provided through the Commission's prior rate order. Staff denies that its proposal will create a subsidy from sales to transportation customers. In contrast, Staff argues that its proposal corrects the inequity that occurs when a customer must give up storage when switching to transportation service as transportation customers receive too little storage. Staff explains that sales customers benefit from storage assets both in terms of meeting peak day requirements as well as seasonal hedging regardless of their size. If a sales customer loses all or part of that benefit when they switch to transportation service, Staff maintains that they will be unduly deterred from transportation service.

Staff seems to suggest that once at the workshops, the participants should use the bank capacity calculation methods of Nicor or Peoples/North Shore to determine appropriate bank sizes for the AIU systems. Peoples and North Shore use a method that allocates the total system storage capacity (on- and off-system) divided by system deliverability on a peak day. Staff conducted a comparative analysis and found that if AIU were to allocate its storage using the Commission-approved method used by Peoples and North Shore, transportation customers' allocation would be 37, 35, and 27 days of MDCQ for AmerenCILCO, AmerenCIPS and AmerenIP, respectively. Nicor allocates total on-system storage capacity divided by the peak design day demand. Staff determined that if AIU were to allocate its storage using the Commission-approved method used by Nicor, transportation customers' allocation would be 24, 11, and 24 days of MDCQ for AmerenCILCO, AmerenCIPS and AmerenIP, respectively.

Despite objecting to the use of the Nicor or Peoples/North Shore methods, Staff contends that AIU has presented no clear reason to support its objections. According to Staff, AIU's witness on this issue, Kenneth Dothage, appears to be unfamiliar with the methods utilized by the other gas utilities. Moreover, Staff notes that he attempts to impose operational significance on these results. This is something that Staff does not propose or even suggest, and something that the Commission does not do. Staff asserts that it, Nicor, Peoples, North Shore, and the Commission all understand the purpose of these bank sizing calculations and the logic behind why such calculations makes sense. Staff adds that these methods have not even been contested in other gas utilities' rate proceedings.

In comparing the cost allocation methods, Staff states that a peak day allocator favors sales customers. Smaller customers generally have usage that is largely influenced by heating load and is therefore more weather sensitive. Thus, Staff continues, they represent a relatively larger portion of peak day demand relative to annual usage than transportation customers who tend to include larger process load customers. Therefore, transportation customers' share of annual use is greater than their share of peak day use. If capacity is allocated to individual customers based on their peak day usage (or MDCQ) or the "days of bank" and allocate underground storage costs based on peak day deliverability, then Staff believes that it makes sense to divide the seasonal bank capacity into peak days. While Mr. Dothage objects to using a peak day allocator and claims that the annual capacity and peak day demand are not related, Staff notes that AIU witness Normand uses a peak day allocator to allocate annual underground storage costs to transportation customers.

Staff advises the Commission to be wary of AIU's claim that bank unbundling may be hampered by (1) a lack of additional off-system storage and/or (2) off-system storage that is only available at a higher cost than existing assets. Staff states that these claims are similar to arguments made by AIU in its last rate cases. (See Docket Nos. 07-0585 - 0590 (Cons.), Ameren Ex. 30.0) After imposing a bank size equal to ten times a customer's MDCQ, however, Staff points out that these fears went unrealized.

Staff explains that AIU's fears failed to materialize because migration of customers from sales to transportation service reduces AIU’s peak day or seasonal storage requirements. The reason for the decrease is that transportation customers must deliver most of their peak day usage from the interstate pipelines, getting the remainder of their needs from their banks using AIU’s storage resources. In contrast, a sales customer receives his entire supply from AIU either through AIU’s deliveries into its systems or from on system storage assets. Staff adds that net migration is overwhelmingly from sales service to transportation service. AIU identifies only one instance of a customer moving from transportation service to sales, which resulted from the elimination of a unique transportation service. Staff states further that it seems very likely that its proposals will make transportation more attractive to customers and that net migration to transportation service will continue.

With regard to AIU's claim that additional off-system storage capacity would be necessary but unavailable, Staff points out that after increasing the bank size in the prior rate cases, AIU is now reducing its off-system storage capacity. This is so, Staff observes, even though the storage capacity devoted to AmerenIP transportation customers increased over 450% following AIU's last rate Order. Staff reports that the only change in AmerenIP’s off-system storage was a reduction of 15% in its Mississippi River Transmission storage contract level. AmerenCILCO and AmerenCIPS experienced similar results. In response to AIU's claim that it could not currently obtain additional off-system storage if it needed it, Staff contends that this is not surprising since capacity is usually not available during the withdrawal season.

b. AIU Position

AIU notes that the current bank size provisions went into effect in October 2008 and claims that insufficient data exists to make an informed decision that would warrant any material changes to the balancing or metering requirements. AIU has not recommended any operational changes to the transportation services. AIU notes, however, that Staff makes two recommendations with regard to the bank size. First, Staff recommends that bank service be unbundled from base rates as part of AIU's next rate cases and that bank service be provided as a subscription service. Second, Staff recommends that the Commission determine the bank size in the next rate cases based on a specified methodology. AIU agrees that these issues should be addressed in its next rate cases and has agreed to participate in the public workshops proposed by Staff. AIU would welcome the input at the workshops of all those interested. AIU, however, urges the Commission to not implement any changes to the Rider T banking program as part of these rate cases.

If the Commission directs that workshops be held on these issues, AIU recommends that it refrain from mandating specific tariff or rate structures or otherwise inhibit the workshop process. According to AIU, the workshop process will be best served by letting the participants determine the nature and scope of the discussions. An unfettered workshop process, AIU continues, will permit the participants to identify the unbundling structures that best serve AIU and the customers. AIU adds that any interested party can present alternative positions in the next rate cases if they wish.

With regard to the concept of allowing transportation customers to determine the size of the bank that they desire and are willing to pay for, AIU asserts that a reasonable approach to follow in the workshop process would be to first identify the available resources needed to support the bank service, determine the price/cost of the resources, make the service available at a specified price and then let the customer elect a certain level of bank service. AIU states that it would be inconsistent to allocate a fixed amount of capacity to all such customers and permit each to choose the amount of capacity it desires from that fixed amount until the fixed amount is spoken for. AIU maintains that the Commission should not address the merits and applicability of the Nicor and Peoples methods in this case. Likewise, the Commission should not limit the workshop discussion to the Nicor or Peoples methods.

In response to Staff's suggestion that the Peoples and Nicor methods should be used to guide the determination of the appropriate size of the Rider T banks in the workshop process, AIU argues that they produce meaningless results when applied to AIU and should be rejected. AIU alleges that the methods have material defects that may not have been identified in previous Commission proceedings. AIU maintains that the Commission should not require it to follow either of these methods simply because they have been previously used by other utilities, without first reviewing the results of their application to AIU. AIU relates that the Peoples method divides the utility's total storage capacity by the utility's system's total deliverability on a peak day. The Nicor method divides the on-system storage capacity by the system's total deliverability on a peak design day. Both methods purport to arrive at a number of days of peak deliverability. AIU contends that the defect of both methods is that there is no relationship between the numerator of the equation (storage capacity) and the denominator (peak day deliverability of the system). AIU asserts that the methods are merely mathematical calculations that do not speak to the operational issues or system constraints. The methods, AIU continues, do not show any real relationship between the seasonal working inventory of the storage field and the system peak day deliverability. One is an inventory volume over the entire five month winter season, while the other is a daily deliverability volume. AIU states that dividing the two produces a mathematical result, but that result does not have a rational meaning in the real world of physical deliverability and capacity.

AIU states that Staff's suggestion that the Commission consider the Nicor and Peoples models in the future might result from a failure to appreciate the difference between a storage field's peak day deliverability and its total storage capacity. A storage field can not release 100% of the gas in storage on the peak day. As an example, AIU states that AmerenCILCO's on-system storage has a total capacity of 8,172,473 MMBtu, but AmerenCILCO can only withdraw 190,000 MMBtu from those fields on a peak day. While there is some relationship between the peak day withdrawal capabilities and total system peak day deliverability, AIU argues there is no relationship between the total storage capacity and total system peak day deliverability.

AIU further argues that determining the unbundled bank size using either of the Nicor or Peoples methods will have a negative impact on the system sales customers because any additional seasonal storage capacity that is allocated to support additional days of banking for the transportation customers ultimately will be seasonal storage capacity taken away from the system sales customers. If it must provide additional days of banking rights to the transportation customers, AIU claims that it will have to acquire new seasonal storage capacity for their sales customers to replace the storage allocated to the increased banking service. AIU indicates that the availability and cost of additional storage capacity is unknown. AIU claims that its 821,300 sales customers could suffer for the benefit of its 481 transportation customers. AIU adds that in order to unbundle appropriately the Rider T banking service, a portion of each gas supply system resource would need to be carved out and packaged in a separately priced banking service.

c. IIEC Position

IIEC strongly supports the concept of workshops prior to AIU's next rate proceeding to discuss unbundling Rider T's bank from base rates and determine equitable methods of allocating both storage capacity and costs. IIEC is particularly interested in Staff's recognition of the need to coordinate changes in capacity rights with cost allocation procedures. Unless both aspects of the rate design process are treated consistently, IIEC states that there is no guarantee that customers will truly realize any unbundling of assets approved by the Commission.

d. CNE-Gas Position

CNE-Gas supports bank unbundling and notes that in 2008 it urged the Commission to study the utilization of the Nicor and Peoples bank allocation methodologies in order to more equitably allocate assets between sales and transportation customers. CNE-Gas further suggests that the existing bank limits are inequitable and contends that AIU has provided no empirical evidence to support retention of ten days of storage for transportation customers based upon its actual storage assets. CNE-Gas requests that the Commission remedy the existing inequitable allocation of storage assets. Illinois utilities, CNE-Gas continues, have used one of two Commission-approved methodologies for a number of years and both are viable options. At minimum, CNE-Gas states that the Commission should direct AIU to review its current storage allocation methodologies in order to assure equitable storage allocation between sales and transportation customers. CNE-Gas adds that AIU should be required to work with Staff and other interested parties to develop a proposal to unbundle storage for transportation customers that will be included in AIU’s next rate case filing.

e. Commission Conclusion

At the outset, the Commission wishes to assure all parties that it will not be directing any changes to the banking provisions of Rider T in this Order. All parties appear to agree that workshops should be held prior to AIU's next gas rate cases for the purpose of discussing alternatives to AIU's current banking terms and conditions. The Commission favors this approach as it may reduce the number of contested issues in AIU's next gas rate cases.

As for the subject of the workshops, which should be open to all those interested, the Commission notes less agreement by the parties. While Staff proposes that specific methods employed by other Illinois gas utilities be considered and modified for use by AIU, AIU urges the Commission to refrain from limiting discussion in any way. The Commission finds merit in Staff's proposal since it concerns methods which it is familiar with and would promote consistency among the gas utilities operating in Illinois. Customers with facilities served by differing gas utilities are apt to find such consistency attractive. AIU's view, however, deserves consideration as well. By directing that the workshop participants develop tariffs implementing the same banking provisions of Nicor, Peoples, and North Shore, the Commission fears that it would be making a decision before having all of the facts. In light of AIU's arguments, enough doubt exists over whether the practices of Nicor, Peoples, and North Shore are appropriate for AIU that the Commission is not comfortable with limiting the workshop discussions.

To resolve this issue in a way that would be most beneficial to its ability to address these questions in AIU's next gas rate cases, the Commission directs AIU and Staff to participate in workshops which will at a minimum result in tariffs implementing for AIU the banking provisions currently employed by Nicor, Peoples, or North Shore. Said tariffs are to be provided in AIU's next gas rate cases. AIU is also free, however, to raise at the workshops its concerns about adopting such banking provisions. AIU may submit in its next gas rates cases as an alternative to what Staff seeks tariffs implementing banking provisions that AIU believes are appropriate. The workshops shall be open to any other stakeholders wanting to participate. The Commission expects all participants to take AIU's concerns seriously. By requiring proposed tariffs implementing either the Nicor or Peoples method but also giving AIU the option to offer an alternative, the Commission preserves for itself flexibility in determining the most appropriate banking provisions under Rider T for AIU. Nothing in this conclusion should be read to prohibit any other party in AIU's next case rate cases from proposing other banking provisions.

E. Contested Electric Issues

1. Overall Rate Design

a. AIU Position

AIU's overall rate design utilizes a cost basis as a starting point, applies a rate mitigation approach to the cost basis, and adjusts rates among classifications in an attempt to comport with its own goals as well as those expressed by stakeholders and the Commission. While changes to the DS-1 and DS-2 rate classes are not contested issues in this proceeding, AIU states that the changes are an important component of its overall rate design. Specifically, AIU seeks to conform its rate design to the Commission's Order in the previous rate case with respect to DS-1/BGS-1 space heat customers. AIU also seeks to move closer to rate uniformity among the three companies. To do so, AIU modified its DS-1 rates, in order to move towards a "Straight Fixed Variable" or "SFV" approach. Under the proposed rates, AIU will recover approximately 39% of allocated delivery service charges through the customer and meter charges, an increase from the current rates. The change to the BGS-1 supply rate structure compliments this approach and refines AIU's approach to rates for customers using electric space heating. AIU states that the changes to BGS-1 are complimentary to the changes to DS-1. Rates for classes DS-2/BGS-2 are also realigned in this manner.

AIU also proposes changes to general service (DS-3) and large general service (DS-4) customers. The rate design for these classes remains a contested issue. Similarly, rate design for lighting customers (DS-5) remains a contested issue.

AIU recognizes that the Commission is unlikely to approve its requested revenue requirement without change. The conformance of the final rates to the adjudicated revenue requirement is an essential task in this case. AIU proposes that the final rates be adjusted to meet certain rate design objectives, which AIU contends provides a better balance between movement toward cost-based rates and mitigating bill impacts. AIU states that its approach recognizes that simply shifting rates based on some percentage places disproportionate rate burdens on certain customer classes. Specifically, AIU proposes to retain all Customer, Meter, Transformation, and Reactive Demand charges for all the rate classes. Then, for DS-1 and DS-2 classes, AIU would adjust Distribution Delivery Charges based on a uniform percentage, in order to achieve the final rate requirement. For the DS-3 class, AIU proposes to achieve final revenue targets through a uniform percentage reduction to the $/kW Distribution Delivery Charge for each of the companies. Finally, for the DS-4 class, AIU proposes to adjust the new variable Delivery Charge to a level to match the revenue target, but not lower than one half of the average PURA tax amount. If necessary, AIU would also lower the DS-4 $/kW Distribution Delivery Charge in order to achieve the revenue allocation target. AIU reports that its approach has been used by the Commission in the past. (See, e.g., Docket No. 91-0335 at 70-72; Docket No. 93-0183 at 90-107; and Docket Nos. 99-0120/99-0134 (Cons.) at 64.)

While Staff's and IIEC's across-the-board approach to conforming rates with the final revenue requirement is easy to administer, AIU maintains that their approach misses an opportunity to address subsidy elimination, rate continuity, and bill impact concerns. The Staff and IIEC approach, AIU continues, also misses an opportunity to better address concerns raised by various parties in this case. For example, AIU contends that Staff's approach exacerbates a problematic divergence between DS-3 and DS-4 delivery rates and, as such, fails to address this important concern. Because such an oversimplified approach strays from the goals of cost-based ratemaking and mitigating bill impacts, and AIU's approach embraces those goals, AIU asserts that its rate design approach should be approved by the Commission in this docket.

b. Staff Position

Staff generally supports AIU's rate design for the BGS classes and DS-1 and DS-2 classes, but disagrees on how the DS-3, DS-4, and DS-5 rates should be designed. Given the Commission's stated preference for SFV rate design, Staff considers AIU's proposals for the DS-1 and DS-2 rate classes acceptable in this case. Staff considers AIU's proposals to be a reasonable solution to the challenges posed by the rate redesign conducted in Docket No. 07-0165. In that proceeding, the Commission faced a common problem of disproportionate bill impacts for customers with high consumption levels in non-summer months. For each class, the problem was addressed by reducing BGS supply charges for higher usage blocks in the non-summer months and increasing other BGS charges accordingly. These adjustments in Docket No. 07-0165 have created a discrepancy between supply charges and costs. To reduce these imbalances, Staff relates that AIU proposes to move tail block non-summer rates closer to costs.

While Staff suggests that the Commission consider raising non-summer tail block rates for the DS-1 class, it does not make a similar proposal for DS-2 customers. Staff explains that it does not do so because the gap between BGS charges and costs for bundled DS-2 customers in the non-summer tail block is not nearly as great as for residential DS-1 customers. For some residential customers, the current per kWh tail block supply charge falls to one cent or below while for bundled DS-2 customers the charge remains above 4¢/kWh. Staff states that this much smaller gap between supply charges and costs for residential space heating tail block usage provides the reason to suggest that the Commission consider going further than AIU proposes to raise that supply charge for residential customers.

With regard to conforming the final rates with the final revenue requirement, Staff prefers to lower all DS components to achieve the final revenue requirement allocated to a class. In order to accomplish that goal, Staff recommends adjusting the rates that are uniform among the three companies – Customer, Meter, Transformation, and Reactive Demand Charges – on a combined AIU basis, and then adjusting the remaining rate components by an across-the-board amount to achieve the desired revenue target. Staff favors its rate adjustment methodology over AIU's because it considers its own method simpler to implement.

Staff adds that compliance rates are not a good place in which to adjust rates for specific rate design objectives. Any changes to rates at that juncture have important implications for all AIU ratepayers. To the extent that one rate element is adjusted and another is not, Staff fears that certain ratepayers will benefit while others will be disadvantaged. The problem, Staff continues, is that no ratepayers have recourse at this stage of the process. If a group of customers loses out, Staff states that they must wait until the next rate case to seek redress. In contrast, Staff observes that its equal percentage adjustment approach to compliance rates has the same impact on all ratepayers. Staff points out that ratepayers will know they receive the same treatment as everyone else in the adjustment of their rates to the final revenue requirement. Staff contends that this is more transparent and equitable.

c. IIEC Position

With the three exceptions of (1) AIU's proposed collection of PURA taxes through a new line item charge on customers' bills, (2) the combination of the DS-3 and DS-4 classes for Distribution Delivery Charges, and (3) the failure to allow for combined billing for multiple meters on the same or adjacent premises, IIEC does not oppose the basic rate structure and design used by AIU, which are mostly consistent with prior rate determinations. IIEC, however, does have some concerns regarding how to conform the final rates with the approved revenue requirement. The problem with both Staff's and AIU's approach, IIEC argues, is that they begin with AIU's flawed COSS, which are used to develop class revenue allocations under both of their proposals. IIEC complains that adjusting proposed rates downward on a full across-the-board basis, as proposed by Staff, or by a constrained across-the-board basis as proposed by AIU, will maintain the underlying class and subclass revenue allocations proposed by each. Since these revenue allocations are based, at least in part, on the flawed cost studies, IIEC asserts that they result in the same objectionable revenue shifts between classes. To address such concerns, IIEC recommends starting with current rates and adjusting rates upward on an across-the-board basis to meet the utility revenue requirements, which would result in minimal or no cost shifting between classes.

If the Commission accepts AIU's COSS for revenue allocation and rate design purposes and decides to increase rates from current rates on something other than an across-the-board basis as recommended by IIEC, IIEC originally suggested that the Commission order AIU to rerun its COSS and determine class and subclass revenue allocations in accordance with the Commission's findings in this case. In that event, IIEC supported Staff's method to adjust downward the resulting rates on an across-the-board basis to conform the rates to the final utility revenue requirements. If, however, the rerun cost studies also reflected the final approved utility revenue requirements, IIEC stated that no downward scaling would be needed.

IIEC originally preferred Staff's position over AIU's if its own was not adopted at least in part because it found AIU's approach to final rate conformance unclear. After having reviewed AIU's Reply Brief and giving AIU's approach more consideration, however, IIEC now favors that approach if the Commission does not accept IIEC's position on the PURA tax and allows AIU to establish a new tax line item on delivery service bills. IIEC believes it would be appropriate to reduce the charge associated with that new line item as much as possible in order to conform rates to class or subclass revenues resulting from lowering the revenue requirement. If AIU’s position on the conformance of rates to the approved revenue requirement includes lowering the proposed DS-4 PURA tax charge as described by AIU witness Jones (see Ameren Ex. 40.0 Second Revised at 15-17), IIEC now supports AIU's proposal if its positions on the relevant issues are not adopted by the Commission. While Staff’s approach does not address the onerous PURA Tax charge, it is IIEC’s understanding that AIU's approach does. IIEC, however, believes that AIU has not provided justification for limiting the reduction in the charge to one-half of the PURA tax amount as recommended by Mr. Jones, and therefore recommends that the artificial limitation be eliminated, allowing the tax charge to be reduced as much as needed to conform the class or subclass rates to the reduced revenue requirement.

d. Commission Conclusion

Except as modified below, the Commission generally finds AIU's electric rate design acceptable. In addition to the modifications set forth below, however, the Commission must also determine to what extent the overall rate design should change to reflect the final revenue requirement adopted in this proceeding for each electric utility. As discussed above in the context of cost allocation, the Commission does not find AIU's electric COSS fatally flawed and will therefore not be implementing an equal percentage across-the-board change to reflect the final revenue requirements. Instead, after rerunning the COSS as directed above, adjustments will need to be made reflecting the difference from AIU's proposed revenue requirements and the approved revenue requirements.

Despite some ambiguity and changing positions, the Commission believes that it understands the positions of AIU, Staff, and IIEC. The Commission finds that a simple approach in this situation is preferable. As proposed by AIU, the Customer, Meter, Transformation, and Reactive Demand charges for all of the rate classes should be retained. Any change in the revenue requirements should then be reflected through a uniform percentage reduction in the Distribution Delivery Charges for the DS-1 through DS-3 rate classes, which is consistent with what the Commission understands AIU to be proposing for these rate classes. For the DS-4 rate class, AIU's proposal appears to be a form of rate mitigation for larger customers. The proposal appears reasonable and as it is endorsed by IIEC, the Commission accepts it for purposes of this proceeding. The Commission finds AIU's proposal in this context for the DS-5 class acceptable as well.

2. Rate Moderation/Mitigation

In order to establish a rate design, AIU and Staff utilized the results of their respective electric COSS methodologies and applied mitigation strategies to underlying cost indicators. Given its concerns with AIU's COSS, IIEC developed a mitigation strategy separate from a COSS. Those mitigation strategies serve an important role in promoting rate continuity and rate stability while considering potential bill impacts that could result as rates are moved toward the actual cost of service.

a. AIU Position

AIU proposes to mitigate bill impacts resulting from this rate case by limiting the increases to rate classes DS-1 through DS-4 to 125% of the system average increase, excluding the DS-5 class and the PURA tax. AIU excludes the PURA tax from its rate mitigation calculations because it is assessed to utilities on a kWh or energy basis, which leads AIU to believe that the tax should be assessed to customers in the same manner, without effectuating cross-subsidies that would otherwise invariably be created by rate mitigation strategies. According to AIU, Staff acknowledges that the ultimate effect of "mitigating" cost assignments by including the impact of the PURA tax assessed to utilities would be subsidized rates. Staff further acknowledges, AIU adds, that using AmerenCILCO as an example, DS-2, DS-3, and DS-4 customers would be receiving a subsidy on a class total revenues basis, inclusive of a portion of the PURA tax associated revenue requirement. AIU therefore concludes by the process of elimination that the incremental effect of including the PURA tax in a rate mitigation approach serves to increase the subsidy burden imposed upon residential (DS-1) and lighting customers (DS-5). AIU argues that it is intrinsically unfair to hold residential and lighting customers responsible for tax liabilities that would not exist but for the kWh usage of larger customers. In other words, AIU does not believe that it is appropriate to collect tax costs from any ratepayers other than those that created the tax obligation. AIU claims that its proposed revenue allocation approach provides a better balance between movement toward cost-based rates and mitigating bill impact.

In response to Staff's proposal to constrain rate increases to 150% of the overall average, including the PURA tax, AIU argues that doing so would put a disproportionate burden on classes DS-3 and DS-4, and, consequently, widens the gap between DS-3 and DS-4 on a dollar per kW demand charge basis. Even if the Commission adjusts the revenue requirement downward due to proposals by the parties, AIU states that the relative differences and relative magnitude of the difference remains the same. AIU maintains that the disproportionate burden created for the DS-3 and DS-4 rate classes under this approach moves away from the stated goal of cost-based rates and mitigation of bill impact. Regarding Staff's concerns for the DS-5 class, AIU defends the fixture charges as promoting rate uniformity across the three utilities, consistent with the Commission's Order in AIU's last rate proceeding.

In response to IIEC's proposal to limit increases (if rates are based on AIU's COSS) to the overall average plus 25% for each class or subclass, inclusive of the

PURA tax, AIU contends that the problem with this proposal is that it defines “subclasses” based on the customer’s supply voltage and customers often use more than one voltage. AIU points out that many customers take service supplied at a higher voltage than that delivered and metered. AIU urges the Commission to reject IIEC’s proposed rate mitigation method because it is lacking in both detail and guidance.

AIU suggests further that IIEC does appreciate AIU's obligation to consider both its large and small customers when it developed its rate mitigation proposal. So, to the extent that a small number of customers experience a larger-than-average rate increase, AIU contends that those increases are consistent with the principles of rate mitigation. AIU asserts that its proposal is simply the most equitable for the rate classes, collectively.

AIU also acknowledges the concern expressed about bill impacts on small customers and maintains that such concern is justified. After power supply price increases followed AIU’s emergence from a ten-year rate freeze in 2007, it had to redesign its rates in Docket No. 07-0165, in order to address rate continuity issues. As a result of that proceeding, and the rate increases that resulted from it, AIU states that it must examine rate design changes for small customers carefully. On the other hand, however, AIU states that it also considered bill impacts to large customers, as evidenced by the fact that its proposed mitigation strategy utilizes a 125% revenue allocation constraint for all the customer classes, including DS-4.

Additionally, IIEC contends that AIU’s rate moderation approach is inappropriate because AIU examines bill impacts on a total bill basis. Instead, IIEC contends that AIU should consider only the Distribution Delivery Charges when determining rate impacts. AIU counters that doing so would not provide it or the Commission with an adequate indicator of true bill impacts on customers. Instead, AIU continues, IIEC’s approach benefits customers who currently have low delivery service rates, because any substantive increase to those rates results in a much higher percentage increase. AIU maintains that its total bill approach is the only way to truly understand bill impacts here. AIU attempts to demonstrate its point by way of an example using postage delivery rates. AIU asserts that delivery charges, whether they are for a parcel or electricity, are a concern for consumers within the context of the overall bill or transaction. If an individual is thinking about ordering merchandise for home delivery, the impact of the shipping charge is relevant within the overall context of the economics presented by the transaction. According to AIU, a consumer would not exclude the price of the merchandise in deciding whether the shipping rates are unreasonable. If a person is debating whether to order a $1000 oil painting, and the gallery decides it will increase its shipping charges from $30 to $60 dollars, the purchaser is confronted with a total price for the item that has increased by approximately 3%. On the other hand, if the customer is purchasing a $50 reproduction print, the differential in the shipping price becomes more material to the customer’s economic choices. AIU believes that this example shows that examination of total bill impacts is a common sense approach.

b. Staff Position

Staff proposes to allocate electric revenues according to their underlying costs subject to the limitation that no class would receive an increase greater than 150% of the system average increase. While Staff contends that its proposal appropriately balances costs and bill impact concerns, it maintains that AIU's alternative proposal to limit increases for any individual class to 125% of the system average increase is contradictory and confusing. Staff adds that AIU's proposal excludes PURA taxes from the constraint and thereby produces much larger increases for individual classes.

Staff understands that AIU wishes to mitigate the impact of any rate increase stemming from this proceeding in light of the difficulties ratepayers have encountered in recent years adjusting to electric rate increases. Staff notes that the relative newness of the then current rates during AIU's last rate case contributed to the Commission decision to adjust rates on an across the board basis. Staff further notes that AIU now believes that sufficient time has passed and circumstances have changed enough to warrant taking steps again toward implementing cost-based rates while attempting to minimize rate shock.

The first problem for AIU, according to Staff, is that the rate mitigation constraint it has chosen does not cover costs associated with the PURA tax. AIU appears to believe, Staff continues, that ratepayers will accept disproportionate increases as long as they are tied to PURA taxes. Staff avers, however, that there is no evidence in the record to indicate that customers make such a distinction. Furthermore, Staff finds AIU's approach to rate mitigation contradictory, since logic which would indicate that ratepayers care about all components of their electric bills including PURA taxes.

The second problem centers on AIU's unequal treatment of DS-5 lighting customers. AIU proposes significantly higher revenues for the lighting classes than justified by the underlying cost. Staff understands that AIU bases this proposal on the ostensible objective of making lighting charges more uniform across the three companies. According to Staff, AIU acknowledges that the result of the DS-5 revenue allocation methodology is revenue reductions of approximately $1.97 million, $1.62 million, and $60,000 reallocated to each electric utility's DS-1 through DS-4 classes. Staff maintains that this allocation is unfair to lighting customers who receive a higher increase than justified by the methodology applied to other rate classes. Staff reminds the Commission that lighting bills are paid by municipalities that, in turn, must recover the costs from taxpayers. If lighting rates go up, the higher costs will be borne by taxpayers. Staff believes that the more equitable alternative is to apply the same revenue allocation rules to all rate classes. Staff also rejects AIU's claim that higher revenue allocations are necessary to make progress toward the goal of equalizing lighting rates. While the Commission directed AIU to address the possibility of doing so, Staff contends that considering the possibility is far different from imposing such higher revenue allocations on DS-5 customers.

The third problem, Staff reports, is that AIU's proposed class revenue allocations rest upon a flawed cost of service foundation that features an NCP allocator for primary distribution lines and substations. To the extent that the COSS deviate from cost causation principles due to this error, Staff states that this error will distort the resulting class revenue allocations regardless of the methodology employed.

Staff, like the other parties to this case, states that it is concerned about bill impacts for AIU ratepayers. Staff adds, however, that bill impacts are not the only concern in allocating the revenue requirement. Costs are important as well. Staff believes that the best way to balance these two concerns is through a constrained class revenue allocation. Staff maintains, however, that any effort to address bill impacts in the revenue allocation process must be consistent and fair to all rate classes. Staff contends that its proposed 150% constraint represents a reasoned judgment of how much progress can be made towards cost-based revenue allocations while addressing bill impact concerns. While the Staff constraint is higher than the AIU proposal (150% vs. 125%), Staff points out that its proposal encompasses all costs in the revenue requirement while the AIU proposal exempts PURA taxes. Staff therefore concludes that its proposal is more consistent and equitable.

Staff's approach accords the largest percentage increases to the biggest customers on the system. This result is largely driven by the reallocation of costs associated with PURA taxes among rate classes. The shift in allocation of PURA taxes from utility plant to usage shifts responsibility for these costs to DS-3 and DS-4 customers who account for 12% and 43% of sales, respectively. Despite this shift, Staff insists that the proposed increases for these classes will not produce an undue increase in their overall cost of electricity. Utility bills for large customers generally extend to delivery service costs only because they tend to purchase power from non-utility suppliers. Thus, Staff asserts that a significant increase in delivery services does not necessarily translate into a large increase in the overall cost of electricity.

Staff insists that its approach is more equitable for DS-5 customers as well. Staff essentially argues that AIU has arbitrarily increased lighting rates above the cost of service for the sake of consistency among the three utilities. According to Staff, AIU readily admits that it has applied one standard to lighting customers and another to all remaining customers. Staff states that this is clearly unfair to the lighting class. When utilities factor bill impacts into the revenue allocation process, Staff maintains that their approach should be based on a transparent set of rules fairly and consistently applied to all rate classes to ensure that some are not shortchanged in the process. Staff contends that AIU's proposal clearly falls short in this regard.

Staff notes that AIU criticizes its mitigation approach by claiming that a 150% limit puts a disproportionate burden on the DS-3 and DS-4 classes. But later AIU also complains that Staff's approach to distribution taxes would subsidize the DS-3 and DS-4 classes as well as the DS-2 class. Staff therefore understands AIU to argue at the same time that Staff's approach both burdens and subsidizes the DS-3 and DS-4 classes. Staff contends that this confused argument can be readily dismissed by the Commission.

With regard to IIEC's rate mitigation argument, Staff asserts that IIEC's proposals do not appear to satisfactorily address the Commission's concerns about returning the focus of AIU ratemaking to cost of service. Staff recalls from AIU's last rate case that 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." (Docket Nos. 07-0585 et al. (Cons.), September 24, 2008, Order at 281) Staff contends that neither IIEC's proposed across-the-board allocation nor its limited constraint of 25% over the system average increase at the subclass level appears to be consistent with the Commission's statement.

c. IIEC Position

IIEC complains that AIU is requesting an unprecedented level of rate increases for its largest, highest load factor customers but is doing little in terms of rate mitigation for the affected customer classes and subclasses. IIEC contends that the two main failings in AIU's approach are its failure to reflect the impact of the PURA tax in its analysis and its failure to apply its moderation criteria at the subclass level. In contrast to AIU's proposal, IIEC argues that its approach properly recognizes the cost differences and bill impact differences among subclasses within a customer class, rather than considering only "average" impacts of widely varying increases.

Although AIU claims to have taken into account cost impacts and rate moderation, IIEC asserts that the proposed increases for the customers in the DS-4 class illustrate an unfortunate disregard of the principles of rate continuity and avoidance of rate shock. IIEC notes that in some instances the increase in delivery service charges is in excess of 1,000%. For some customers, this translates to increases in delivery costs of over $1 million per year. IIEC contrasts this result with AIU's position on the rate limiter in this case (discussed below) and its response to delivery service rate increases as high as 42% for certain customers subject to the rate limiter. IIEC maintains that the disconnect between AIU's position on the rate limiter and its attempts to justify unprecedented rate increases as high as 1,000% for other customers makes more apparent its intent to impose as much of its rate increase on its largest customers as possible, in order to avoid adverse political responses to its overall rate request in this case. While the Commission may wish to give favorable consideration to AIU's proposal for extension of the rate limiter for grain drying customers, and if it does, IIEC would not object, IIEC urges the Commission to also give favorable consideration to any reasonable recommendation to reduce the level of the rate increase requested by AIU for all customers, and to the specific recommendations of IIEC on appropriate cost allocation and rate mitigation measures in this case.

IIEC accuses AIU of attempting to mask the level of its proposed increases in DS-4 charges by providing comparative statistics that include costs that have no bearing on the delivery service charges that are at issue in this case. IIEC relates AIU's claim that increases of as much of 100% in the delivery bill are acceptable if viewed from the perspective of a total bill that includes power commodity costs. AIU witness Jones' focus on masking the impacts of increases in delivery service bills is understandable, according to IIEC, since he was instructed to do so by Ameren management. IIEC offers the following excerpts from an e-mail exchange between Mr. Jones and AIU witness Mill on May 17-18, 2009:

> By Mr. Jones: "How comfortable are you and do you think others will be showing a DS-4 increase in the 70% - 90% range (56-30% without the Distribution [PURA] Tax influence)?"
>
> Response by Mr. Mill: "If you were to assume 5 cent power for DS-4, what is the weighted bundled increase for the 70-90%?"
>
> Response by Mr. Jones: "The large percentages do not look as bad when power is included…"
>
> Response by Mr. Mill: "On a bundled basis it looks like the % increases for all but primary are near the average bundled price increases that residential will face. If you go this route, you need to be strong in your testimony re a bundled viewpoint to help soften reactions"
> (IIEC Ex. 1.2, [partial Ameren response to data request IIEC 4.09] --tables omitted)

From this exchange, IIEC believes that it is clear that AIU knew the impact its proposals would have on large customers' delivery service bills, including the impacts with and without the PURA tax. But rather than proposing to implement any meaningful rate moderation, IIEC states that AIU chose instead to try to obscure the unprecedented size of its delivery service rate increase to these customers by considering irrelevant costs in its analysis. IIEC insists that costs other than delivery service costs have no bearing on delivery service rates, or the need for rate moderation.

AIU consciously chose to add to the revenue requirement of the DS-4 customers, IIEC continues, in order to benefit the DS-1 residential class. According to IIEC, AIU's strategy is to make the requested revenue increase as palatable for residential customers as possible by shifting cost responsibility to large customer classes. A rate moderation proposal that mutes the impact of the increase on large customers, IIEC continues, might also mute the impact of the revenue shift from residential customers. In an e-mail from Ameren president Scott Cisel to Mr. Jones and Mr. Mill, IIEC states that Mr. Cisel emphasized the need to protect residential customers. In e-mails dated May 25, 2009, IIEC reports that Mr. Cisel makes the following observations:

> "It appears that most of the charges, graphs for residential and small business customers are contained in this exhibit. As we all know, residential and small businesses are lightning rods."

> "I want to better understand the proposed rate changes on residential customers and small businesses and how they will play on 'Main Street'. Good rate design based on the data is important; however if the design causes major public unrest, we will have difficulty in achieving our desired success. Balancing all interest is difficult."
>
> "My intuition tells me without seeing the data a much smaller decrease would seem appropriate for the large usage customers and use the difference to reduce the increase of the lower usage customers."
> (IIEC Ex. 1.0-C at 15)

In addition, in an e-mail dated the following day, May 26, 2009, IIEC relates that Mr. Mill observes, "Scott very concerned re optics and outcry from small customers." (Id.) In light of these comments, IIEC argues that AIU's revenue allocation and class rate increase proposals are not driven by rate making principles such as rate impacts, rate stability, and rate moderation, but by its desire to protect itself from adverse political reaction to its overall increase and to help ensure it receive its desired level of rate relief. IIEC urges the Commission to set delivery service rates that are stable, fair, equitable, and take into account the principles it has espoused in the past and which are present in the Act. IIEC insists that stable rates, that avoid rate shock, are a necessity for all customer classes and subclasses.

To moderate the rates which it complains of, IIEC originally proposed a rate mitigation approach that limits the increase to any subclass' revenues to 25% above the average change in rates of each company's overall increase. But given its concerns over AIU's electric COSS, which came to light in AIU's prepared surrebuttal testimony and cross-examination testimony, IIEC finds itself unable to rely on AIU's COSS to allocate costs and set rates. If the Commission is left without a valid measure of class and subclass cost of service because it can not rely on AIU's COSS, IIEC asserts that it has no basis for shifting revenue responsibility between classes and should implement any increases or decreases to the rates on an across-the-board basis.

IIEC asserts that an across-the-board rate allocation would still address the rate moderation concerns expressed by IIEC and Staff, as the resulting impacts on bills would, by definition, fall within the rate moderation criteria expressed by each. An across-the-board increase in rates affects all classes and subclasses equally, by the percentage increase (or decrease) in revenues. Thus, IIEC states, the 25% above the average increase proposal of IIEC, and the 150% of the average increase proposal of Staff are automatically met. According to IIEC, this approach would also meet the Commission's goal to avoid rate shock and ease rate impacts.

Because of the huge increases that AIU's proposals produce for subclasses within the DS-4 rate class, IIEC maintains that the subclass revenue allocations should include the impact the PURA tax. Should the allocated revenues that result in this case exceed the rate moderation thresholds, IIEC contends that the most reasonable approach to implementing this allocation would be to first spread any revenue deficiencies to other subclasses within a rate class, e.g., DS-4, on a proportional basis, unless and until the 25% above system average threshold is reached for any of the other subclasses. If all subclasses within a delivery rate class reach the maximum of 25% above the system average increase, IIEC recommends spreading any remaining revenue shortfall among the other subclasses, again on a proportional basis. IIEC adds, however, that Staff's rate moderation approach to limit the increase on current rates for any class at 150% of the system average increase approved in this proceeding, including the impact of the PURA tax, would be acceptable, assuming the application is done at the subclass, rather than full class level.

IIEC insists that rate moderation occur at the subclass level since it is the actual bills that customers pay which determine the degree of rate shock. IIEC reports that the bills that the subclasses would pay under the AIU proposed increase in this case are dramatically different, even within the same rate class. IIEC states that the increases in delivery charges vary for the DS-4 class from 35% to 541% for AmerenCILCO, from 24% to 1,270% for AmerenCIPS, and 20% to 760% for AmerenIP. IIEC's point is that, regardless of the final revenue requirement in this case, the actual bills that a customer must pay depends not so much on the class to which it belongs (e.g., DS-4), but on the subclass to which it belongs (e.g., DS-4 100+ kV).

IIEC is also concerned about the effect that recovering the PURA tax as a separate line item will have rate moderation efforts. IIEC maintains that it will be impossible to implement Staff's rate moderation proposal and simultaneously collect an equal PURA tax per kWh charge as a separate line item on the bill. IIEC explains that this is because the PURA tax has such a dramatic effect on the overall delivery service bills of some customer classes and subclasses (See IIEC Ex. 1.0-C at 5: Table 1- -showing class increases of about 60% for DS-4 customers and at 7: Table 2 --showing increases ranging from 78% to 131% for DS-4 High Voltage customers and 541% to 1,270% for DS-4 100 kV and Above customers). Using a uniform PURA tax recovery charge for all customers would require that the base delivery service charges for certain customer classes or sub-classes would need to be reduced to zero, or even go negative, which, according to IIEC, is obviously an illogical result. Of the two factors, IIEC argues that adequate rate moderation is far more important than implementing a new line item on a bill associated with a tax that is already being collected in base rates. Therefore, in order to comply with IIEC's, or Staff's, rate moderation proposal, IIEC states that the Commission must reject AIU's and Staff's proposal to collect the PURA tax charges on a ¢/kWh basis as a separate line item and instead, maintain the current recovery of the costs through base rates.

d. Commission Conclusion

It is a widely held ratemaking policy that rates should be designed to reflect cost causation, maintain gradualism, and avoid rate shock. Given the history concerning AIU's rates and the change in the PURA tax allocation, among other conclusions in this Order, the rate impact on all of AIU's rate classes is of great importance to the Commission. One of the Commission's first observations on this issue pertains to AIU's exclusion of the PURA tax from its rate mitigation proposal. While AIU's reasons for excluding the PURA tax in its proposal are understood, the Commission can not accept them. As argued by Staff and IIEC, the Commission can not agree that customers are not concerned about their bill total as long as increases in individual components are arguably reasonable. Examples may be offered on both sides of the argument, but the fact remains that when it comes time to pay a bill, a customer's budget, whether it be a residential or industrial customer, is impacted by the bill total regardless of the reasonableness of the bill's components. Accordingly, rate mitigation efforts should be looked at from the perspective of the bill total.

Setting aside IIEC's preference for an across-the-board rate change, Staff and IIEC both offer rate mitigation approaches which include the PURA tax. Neither is perfect, but entering an order lacking rate mitigation is not an option. In reviewing the proposals, IIEC's proposal raises a point worth serious consideration. IIEC recommends that rate moderation be implemented at the subclass level. Given the concern over the impact of the change in the PURA tax allocation, the Commission is inclined to agree. Moreover, IIEC has expressed its willingness to accept Staff's rate mitigation approach if it is applied at the subclass level. The Commission sees no reason why Staff's proposal based on a 150% increase limit could not be applied at the subclass level, as suggested by IIEC.

In arriving at this conclusion, the Commission must also find that AIU should continue to recover the PURA tax through base rates, rather than as a separate line item on bills. As IIEC discussed, implementation of the adopted rate mitigation approach would not be practical if the PURA tax is reflected as a separate line item. This conclusion is not meant to alter the earlier conclusion on the allocation of the PURA tax; it is merely meant to address the manner in which the PURA tax is reflected on bills. This is not to say, however, that the PURA tax could never be recovered as a separate line item on customer bills.

3. DS-3 and DS-4 Distribution Delivery Charges

The DS-3 rate class is comprised of non-residential customers that have billing demands ranging from 150 kW up to 1,000 kW. The DS-4 rate class is comprised of all non-residential customers with billing demands of 1,000 kW or greater. There are four basic categories of charges for DS-3 and DS-4 customers: (1) Customer Charges; (2) Meter charges; (3) Distribution Delivery Charges; and (4) Transformation Charges. In addition, DS-4 customers are subject to a Reactive Demand Charge. The first three categories of charges are differentiated by voltage, e.g., secondary, primary, high voltage, and transmission voltage. At each voltage level, the Customer Charge is uniform between DS-3 and DS-4. Likewise, the proposed Transformation Charge is uniform between DS-3 and DS-4 in each service territory. 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. There is no separate Distribution Delivery Charge for secondary voltage. Secondary voltage customers pay the primary Distribution Delivery Charge plus the Transformation

Charge. Unlike the Customer Charge and the Transformation Charge, the Distribution Delivery Charge is not uniform between the DS-3 and DS-4 rate classes.

a. AIU Position

AIU indicates that customers served at lower voltages require additional investment in distribution facilities as compared to customers served at higher voltages. As a result, AIU states that voltage differentiated pricing reflects the costs incurred to serve customers, and is higher for low voltage customers and lower for high voltage customers. AIU proposes Distribution Delivery Charges that were developed using an approach similar to that used to establish prices for the same elements in AIU's second most recent set of rate cases, Docket Nos. 06-0070 et al (Cons.). The distinction being that in this pending proceeding, AIU combined the demand-related costs for the DS-3 and DS-4 classes and divided by the combined voltage differentiated demands.

AIU argues that its revenue allocation approach should be used to determine the Distribution Delivery Charge for DS-3 and DS-4, as it establishes more consistent bill impacts among customer classes. AIU adds that its approach provides for relatively moderate differentiation between classes when compared to Staff's approach. Under Staff's approach, AIU states that AmerenIP and AmerenCILCO DS-3 customers take on a greater burden. AIU indicates that Staff's approach also unnecessarily provides marginal relief to the DS-4 class for each of the three companies. AIU contends that this issue is important when considering that DS-3 customers with larger demands, or DS-4 customers with smaller demands, may reclassify from DS-3 to DS-4, and vice versa. Under Staff's proposal, a customer reclassifying from DS-4 to DS-3 may experience a rate increase if their demand did not drop by an amount more than the price increase. While some difference between the rates is justified, AIU fears that large differences may encourage inefficient use. AIU maintains that Staff's proposal widens the gap between DS-3 and DS-4, increasing the potential for such inefficiency. In response to Staff's contention that the greater burden its method places on the DS-3 class will be mitigated to the extent that the Commission adjusts the revenue requirement downward, AIU states that the relative differences in the revenue requirements and price disparity remain. Because its proposed Distribution Delivery Charges for the DS-3 and DS-4 classes are closer together than those proposed by Staff, AIU asserts that its revenue allocation and rate design will produce final rates that are closer together.

Furthermore, AIU contends that its method for determining the DS-3 and DS-4 Distribution Delivery Charge addresses the concerns of many of the parties. For example, AIU states that its rate adjustment approach reduces DS-3 Distribution Delivery Charges, which closes the gap between DS-3 and DS-4 – a concern of Kroger. AIU adds that it method also reduces the amount of rate limiter credits – a goal of GFA. Moreover, AIU asserts that its rate adjustment approach reduces the proposed DS-4 ¢/kWh charge first, and if necessary, the $/kW Distribution Delivery Charge, which is responsive to the concerns of IIEC. Further, both LGI and AIU contend that there is merit in moving toward more uniform Fixture Charges among the three companies –

AIU's rate adjustment approach moves toward that goal. AIU contends that Staff has overlooked all of these concerns in its approach. Because it considers its proposal directly responsive to many of the concerns of the numerous intervenors, and creates more consistent bill impacts, AIU deems its method preferable to Staff's and urges the Commission to accept it.

In response to Kroger's proposal to bridge the gap between the DS-3 and DS-4 classes by removing 50% of the difference between the DS-3 and DS-4 Distribution Delivery Charges, with an adjustment for the DS-4 reactive power revenues, AIU argues that Kroger's proposal does not measure potential bill impacts for the affected customers. AIU states that Kroger could have prepared that analysis, but did not. Without further analysis by Kroger, AIU asserts that the Commission can not seriously consider the proposal. AIU also observes Kroger's own acknowledgement that it has submitted the same proposal in three consecutive AIU rate cases with no success. AIU agrees that the DS-3 and DS-4 Distribution Delivery Charges should move closer together, but disagrees that now is the time to take such drastic measures, particularly given the ongoing concerns of bill impact and rate mitigation.

b. Staff Position

Staff understands AIU's proposed rates to include a common set of Customer and Meter charges for the DS-3 and DS-4 classes that are set at current levels. For demand charges, Staff states that AIU first develops a unit cost for demand that applies to both the DS-3 and DS-4 rate classes. Staff understands that that unit cost is then adjusted by AIU to reflect that revenue contributions from the DS-3 class will be slightly less than those for the DS-4 class through the year. Because of these adjustments, Staff observes that the demand charges for the two classes diverge to some degree. Staff notes that AIU relies on the Commission's Orders in its prior rate cases to justify combining elements of the DS-3 and DS-4 rate classes. (See Docket Nos. 07-0585 et al. (Cons.), Order at 362-63) A central tenet of AIU's analysis supporting its ratemaking approach for the two classes is the assumption that conceptually, it costs about the same to provide a kW of service to a DS-3 customers as it does a DS-4 customer. AIU's analysis, Staff continues, finds that the $/kW charges for the DS-3 and DS-4 rate classes should be close together.

Staff maintains that AIU's proposal to collectively design rates for the DS-3 and DS-4 classes conflicts with basic principles of utility ratemaking and should be rejected. Because its alternative approach designs rates for the two classes based on each class' costs of service, Staff contends that its way is more reasonable and should be adopted in this case. Staff argues that the problem with AIU's analysis lies with the assumption that it costs about the same to provide a kW of service to DS-3 and DS-4 customers. Staff contends that that is not necessarily the case because a customer's impact on the distribution system depends not just on the level of his or her demand, but also on when that demand takes place. Staff asserts that that is particularly true for facilities such as distribution lines and substations which may be constructed to meet the collective peak demands of many customers from different rate classes. The impact of any individual customer's demand on the cost of a distribution line or substation depends on how his or her demand coincides with the peak demand for that equipment. If one customer peaks when other customers use less, Staff observes that that customer may have minimal impact on the cost of a distribution line or substation. If another customer's peak demands coincide with the collective peak demands for this equipment, Staff relates that the utility may find it necessary to invest in more capacity. Therefore, because not all electricity demands are the same from the standpoint of distribution costs, Staff asserts that there is no reason to assume that unit demand costs for DS-3 and DS-4 customers will be comparable. Staff points out that AIU witness Jones even acknowledges that "one class may have a greater contribution to the peak demand than another, thus yielding different costs per kW." (Ameren Ex. 40.0 Second Revised at 8)

As alluded to above, Staff also complains that AIU's combined ratemaking approach for the DS-3 and DS-4 classes conflicts with general ratemaking principles which first allocate costs to individual rate classes and then design rates to recover those costs from individual ratepayers. Customers are placed into different rate classes because their usage characteristics are assumed to have a differing effect on system costs. Staff contends that AIU's combined approach does not fully recognize these cost differences and instead essentially treats the DS-3 and DS-4 classes as a single class for ratemaking purposes with some adjustments thrown in to reflect some differences between the two classes. Staff believes that AIU's proposal would send inaccurate price signals to DS-3 and DS-4 customers about their relative cost of delivery services. Specifically, it would understate the cost of delivery service for DS-3 customers and overstate the cost for DS-4 customers. Staff states that this would signal customers in the two classes to use either too much or too little electricity, resulting in an inefficient level of use.

Staff complains further that the assumed commonality between DS-3 and DS-4 customers for rate design inappropriately lumps together customers that are much different in size. Customers in the DS-3 class have demands ranging from 150 kV up to 1 MW while DS-4 class demands range higher. A common rate design for the two classes would lump together 150 kW customers with customers 10 MW or larger. The cost of serving these two customers can be considerably different simply because of their relative demand sizes without considering their respective load shapes.

In response to Staff's concerns about size differences among customers, AIU asserts that its rate design method carefully groups customers by voltage level such that customers' demands supplied from Primary Voltage are grouped together, as are those from High Voltage and +100 kV groupings. Staff contends that this argument is undermined by the fact that DS-3 and DS-4 customers face the same set of customer charges with differences based solely on voltage levels under AIU's proposal. As an example, Staff states that a 500 kW DS-3 customer could pay a higher customer charge than a 5 MW DS-4 customer if the former was served at a higher voltage level. The fact that the DS-4 customer's demand is ten times as high as for the DS-3 customer would play no role in determining their relative customer charge levels. Staff maintains that this is an unreasonable assumption on AIU's part.

Staff notes as well that AIU's cost of service and rate design approaches for the DS-3 and DS-4 classes are fundamentally inconsistent. Staff explains that AIU considers the classes different from a cost of service standpoint, but then lumps them together for the purpose of designing rates. Evidently, AIU believes there are sufficient cost differences between the two groups of customers to justify putting them into two separate classes for allocating the cost of service. Staff points out, however, that AIU then fails to recognize those differences in cost when it comes to rate design. Staff asserts that it is illogical to allocate costs separately to the DS-3 and DS-4 classes and then implement a collective rate design that tries to paper over the cost differences between the two.

Staff presents an alternative which designs rates separately for the two classes based on the respective costs and billing determinants for each class. Staff maintains that designing rates for the DS-3 and DS-4 classes separately promotes equity by ensuring that customers in each class pay rates designed to recover the costs that have been allocated to that class. The alternative approach of collectively designing charges that apply to both the DS-3 and DS-4 classes produces rates for customers in each class that do not necessarily correspond to the level of costs they have been allocated. Staff states that AIU's approach can result in an over-recovery of costs for one class and under-recovery for the other.

c. IIEC Position

Because AIU's approach to determining Distribution Delivery Charges has the effect of combining the DS-3 and DS-4 rate classes for cost allocation purposes, IIEC opposes this rate design approach. IIEC argues that AIU's approach is inconsistent with traditional ratemaking, which first allocates costs to rate classes and then designs rates to recover costs from customers within each class. Costs are generally allocated to classes of customers with similar cost characteristics. IIEC complains that AIU's approach, in contrast, treats the DS-3 and DS-4 classes as a single rate class and obscures the level of costs imposed by members of the classes. Despite AIU's assertions to the contrary, IIEC insists that this rate design approach is not consistent with any past Commission orders. IIEC also criticizes AIU's approach for ignoring the differences in size of DS-3 and DS-4 customers. Similarly, IIEC disagrees with Kroger that delivery voltage is the most accurate indicator of the cost to serve a customer. Thus, IIEC concludes that AIU fails to give consideration to the fact that customers with different demand sizes can impose different costs on the system. Finally, IIEC contends that there is no reason to assume that DS-3 and DS-4 customers have comparable unit demand costs. Under the circumstances, IIEC recommends that AIU’s approach to the design of rates for the DS-3 and DS-4 classes in this proceeding be rejected.

d. Kroger Position

While AIU proposes a uniform Customer Charge and Transformation Charge between the DS-3 and DS-4 classes, AIU proposes a Distribution Delivery Charge for the DS-3 class that is notably greater than that proposed for the DS-4 class. Kroger is very troubled by this and believes that it is appropriate for the Distribution Delivery Charge for customers on the DS-3 and DS-4 rate schedules to be approximately equalized. To reach this objective, Kroger recommends that the Commission initiate steps to move these rate schedules closer together in this proceeding.

Table KCH-1 in Kroger Ex. 1.0 sets forth AIU's proposed Distribution Delivery Charges:

Utility Distribution Company Voltage	DS-3 Charge ($/kW)	DS-4 Charge ($/kW)
Ameren CILCO		
Primary Service	5.711	3.016
High Voltage Service	1.643	0.954
+100 kV Service	0.049	0.033
AmerenCIPS		
Primary Service	4.706	3.041
High Voltage Service	2.054	1.375
+100 kV Service	0.098	0.077
AmerenIP		
Primary Service	7.278	5.597
High Voltage Service	2.403	1.771
+100 kV Service	0.162	0.139

As seen in Table KCH-1, AIU's proposed DS-3 Distribution Delivery Charge for Primary Service is 30% greater than the proposed DS-4 counterpart in the AmerenIP territory. In the AmerenCIPS territory this difference is 55%, and in the AmerenCILCO territory, this difference is 89%. Kroger points out that this means that a Primary Service customer in the AmerenCILCO territory with a billing demand of 999 kW under DS-3 would pay a total Distribution Delivery Charge bill that is nearly 90% greater than an otherwise identical customer with a billing demand of 1,001 kW taking service under DS-4.

Kroger observes that although AIU proposes a larger percentage increase for DS-4 than DS-3, the two rates nevertheless would move further apart under AIU’s proposal. Kroger recognizes that this statement may appear paradoxical, but insists that it is true. Kroger explains that this is because the Distribution Delivery Charge for the DS-3 class already exceeds that for the DS-4 class, and the proposed increase for the DS-4 class is not sufficient to catch up with the charge for the DS-3 class. Kroger offers an example based in AmerenCIPS' service area. For AmerenCIPS, Kroger states that the proposed overall rate increase for DS-3 is 12.43%, while for DS-4 it is 19.53% (excluding distribution tax). Yet Kroger calculates that the proposed increase for DS-3 is greater than DS-4 for each delivery voltage level, except Transmission Voltage Service. For instance, Kroger notes that the proposed increase for the DS-4-Primary Distribution Delivery Charge is only 5.59%. In contrast, Kroger continues, the proposed increase for the DS-3-Primary Distribution Delivery Charge is 14.47%. Kroger adds that for High Voltage Service, the proposed Distribution Delivery Charge increase for DS-3 exceeds that of DS-4.

Kroger maintains that the widely divergent Distribution Delivery Charges paid by DS-3 and DS-4 customers is not cost-justified. According to Kroger, the most important cost distinction for delivery service is the voltage at which customers take service. Kroger contends that this is a far more important distinction than whether a customer is above or below 1,000 kW of demand which is largely irrelevant insofar as per-kW delivery costs are concerned. Kroger states that AIU even admits that conceptually 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. (See Ameren Ex. 16.0E at 39)

Kroger finds unpersuasive AIU's two arguments attempting to justify the different Distribution Delivery Charges for the DS-3 and DS-4 rate classes. AIU's first argument is that the difference is, at least in part, attributable to the recognition of DS-4 reactive power revenues as an offset to the DS-4 Distribution Delivery Charge. Kroger does not dispute the existence of the reactive power revenue offset, but contends that it is relatively too small to explain the disparity between the Distribution Delivery Charges for the DS-3 and DS-4 rate classes.

AIU's second argument pertains to the more consistent distribution of billing demand during the course of the year displayed by DS-4 customers relative to DS-3 customers. AIU asserts that this pattern of usage justifies a reduced unit demand charge for DS-4 relative to DS-3. While Kroger agrees that, mathematically, a customer whose billing demand is relatively constant throughout the year will produce more revenue than a customer with the identical annual peak demand, but who exhibits more variable billing demands throughout the course of the year, it does not necessarily follow that the demand charge for a class with more constant average usage should be lower than that of a class with more variable usage. To the extent that a class has more variable usage, Kroger contends that this fact is already captured in the billing determinant used to calculate the demand charge. Kroger insists that there is no need to make a further adjustment to account for it (as AIU does in Ameren Ex. 16.11E). Moreover, Kroger asserts that a class with more variable usage (e.g., DS-3) is likely to have greater demand diversity at the time the class NCP is measured, all other things being equal. As individual customers are billed for demand based on their individual peaks (which may not occur at the time of the class NCP), Kroger states that a class that exhibits variable demand patterns may very well warrant a lower demand charge relative to a class that exhibits a more constant demand pattern (but has less diversity at the time of the class NCP). Unless both diversity factors are taken account of, i.e., diversity of billing demand throughout the year and diversity of class demand at the time of class NCP, Kroger states that one can not conclude that a given group of customers warrants a lower demand charge relative to another group based on considering one aspect of diversity in isolation. For these reasons, Kroger contends that AIU's second rationale for a difference in DS-3 and DS-4 demand charges is not persuasive.

Kroger observes that despite offering these two reasons to explain the difference in the Distribution Delivery Charges for the DS-3 and DS-4 rate classes, AIU also concedes that its two reasons can not explain all of the difference. According to Kroger, AIU suggests that imperfections in prior COSS may be responsible, at least in part. (See Ameren Ex. 16.1E at 7) AIU witness Jones, Kroger continues, also indicates agreement that DS-3 rates are too high relative to DS-4 rates. (See Ameren Ex. 40.0 Second Revised at 21) Kroger maintains that these statements by AIU as well as AIU's failure to remedy the problem on its own warrant action in this docket moving the DS-3 and DS-4 Distribution Delivery Charges closer together.

In response to Staff's concerns about the impact of load diversity on the cost of serving DS-3 and DS-4 customers, Kroger agrees that load diversity is a key determinant of distribution demand costs. Kroger points out, however, that the question at hand is how that diversity is best captured for the purpose of setting class rates. Rates are not set one individual at a time. Instead, the benefit of the diversity of an aggregation of customers is shared across the group. Kroger's concern is identifying the most appropriate grouping of customers.

Kroger also disagrees with Staff's opinion that customer size matters more than voltage level. For delivery services, Kroger contends that it is voltage that matters most. Kroger argues that there is no evidence presented in this case that the size of individual customer demands for DS-3 and DS-4 customers impacts the unit-cost-of-service for distribution demand. To the contrary, Kroger observes, AIU's COSS shows that DS-3 and DS-4 rates should be converging. According to Kroger, even Staff's discussion of distribution cost focuses on the role of load diversity, which is an entirely separate matter from customer size.

To address its concerns, Kroger suggests that the Distribution Delivery Charges for the DS-3 and DS-4 classes be converged for customers taking service at the same voltage within a given service territory, except for a minor difference to recognize DS-4 reactive power revenues as an offset to the DS-4 Distribution Delivery Charge. To reach this objective, Kroger recommends that the Commission initiate steps to move these rate schedules closer together over time. Specifically, in the current proceeding, Kroger recommends that this first step be implemented by removing 50% of the differential between the DS-3 and DS-4 Distribution Delivery Charges, with an adjustment to recognize DS-4 reactive power revenues. To the extent that the final approved revenue requirement is reduced, then the results for both rate schedules should be adjusted downward while retaining the targeted rate differential. The impact of adopting Kroger’s proposal to remove 50% of the differential between the DS-3 and DS-4 Distribution Delivery Charges is presented in Kroger Ex. 1.4, using the combined DS-3/DS-4 revenue requirement proposed by AIU in this proceeding.

e. Commission Conclusion

The underlying concern with the DS-3 and DS-4 Distribution Delivery Charges is whether these rate classes are sufficiently similar to warrant similar charges. In response to concerns raised by Kroger in prior AIU delivery service rate cases and Commission direction that Kroger's concerns be at least considered, AIU has proposed a rate design for the DS-3 and DS-4 rate classes that it believes will eventually move them closer together. Kroger complains that AIU's proposal does not go far enough and recommends that the Commission go further in this proceeding in closing the gap between the rate classes. Staff and IIEC contend that AIU and Kroger are in error.

At the heart of Kroger's concerns is it position that it does not cost AIU any more to serve a DS-3 customer than a DS-4 customer when both are taking service at the same voltage. Customer demand, in Kroger's opinion, is irrelevant when determining the cost of delivering electricity. Kroger has made this argument in AIU's last two electric delivery service rate cases and in both instances the Commission has indicated that further information was needed before any determination could be made.

Additional information has been provided, but the Commission remains unconvinced that the changes sought by Kroger are warranted. Specifically, the Commission is not persuaded that voltage is the determining factor in cost causation when it comes to delivering electricity. While a factor, voltage is not the sole factor. The Commission continues to believe that customer size/demand plays a role in cost causation as well, as discussed by Staff and IIEC. Even if the Commission agreed with Kroger, it would be hesitant to adopt Kroger's proposal given the absence of any evidence on how it would impact AIU's other customers.

While AIU's class COSS may suggest that moving the DS-3 and DS-4 classes closer together is appropriate, the Commission is not willing to unquestionably rely on those results given the corrections that the Commission has made to AIU's electric COSS. Additionally, the Commission considers separating the DS-3 and DS-4 classes for cost allocation purposes inconsistent with the decision to combine the classes for rate design purposes. Absent compelling evidence that such a rate design is warranted, the Commission declines to adopt AIU's proposal.

The remaining rate design proposal for the DS-3 and DS-4 classes is that of Staff. While not perfect in addressing all of the concerns raised regarding these rate classes, the Commission finds Staff's proposal sufficient for purposes of this proceeding. Accordingly, Staff's proposal on this issue is adopted.

4. DS-5 Fixture and Distribution Delivery Charges

The DS-5 rate class provides customers with dusk-to-dawn, photo-cell controlled lighting service. The distribution charge does not include power and energy, transmission, or delivery service charges, which are separately stated. The distribution charge also does not include the cost of the fixtures, which may or may not be owned by AIU. A monthly Fixture Charge is assessed for street lights that are owned by AIU.

a. LGI Position

LGI pays for street lighting service under AIU's DS-5 rate. LGI claims that in AIU's last rate case, the Commission directed AIU to analyze the cost of lighting service in each utility's electric service area and develop cost based rates for lighting fixture charges. In this docket, LGI understands that AIU's pricing methodology is designed to move Fixture Charges for comparable lights for the three companies to a uniform level. LGI maintains that it is important that the lighting Fixture Charges be uniform across the companies since it is difficult for customers to understand why it costs twice as much for a streetlight fixture in AmerenIP's service area than it does for the same streetlight fixture located in AmerenCIPS' service area, especially where the service areas are literally across the street from each other.

With three exceptions, LGI generally supports AIU's proposal regarding the DS-5 class in this docket. First, LGI asserts that the DS-5 class continues to subsidize the rates for other delivery service classes. Second, LGI complains that AmerenIP's lighting Fixture Charges continue to be significantly higher than the lighting Fixture Charges of AmerenCILCO and AmerenCIPS, without any cost justification. Third, while AIU supports its pricing principles in this case, LGI notes that AIU witness Jones testifies that there may be problems in applying the principle of setting DS-5 rates to achieve equalized class rates of return for each of the three electric systems in future rate cases.

Regarding its third exception, LGI states that Mr. Jones' issue arises as a result of the fact that the Fixture Charges for AmerenCIPS are significantly lower than the Fixture Charges for AmerenIP and AmerenCILCO. In fact, AmerenIP's Fixture Charge is about twice that of AmerenCIPS. So when the Fixture Charges become uniform among the three utilities, in order to meet the targeted revenue requirement for the DS-5 class and achieve equalized rates of return with the other AmerenCIPS DS classes, LGI asserts that any increases to the Fixture Charges for AmerenCIPS would have to be offset by decreases to the DS-5 Distribution Delivery Charge for AmerenCIPS. In other words, LGI states that it is possible in the future that the increase in Fixture Charges for AmerenCIPS would result in a near zero or negative Distribution Delivery Charge for AmerenCIPS.

LGI does not insist that uniformity be established in this proceeding. As long as AIU commits that it will continue to move DS-5 rates closer to equal rates of return in the next delivery service rate case, LGI will be satisfied until then. LGI wishes to withhold final judgment until having the opportunity to review the details of AIU's analysis in the next delivery service rate case.

b. AIU Position

For the DS-5 rate class, AIU took steps to create more uniformity among the Fixture Charges. AIU does not propose full uniformity at this time because it considers the rate changes to accomplish full uniformity too great. AIU constrained rates so that the change in rates results in a change of about $1 per fixture to the high pressure sodium 100 W fixture price. AIU states that it took those steps in response to LGI's concerns in this case, as well as the previous rate case.

Staff, however, contends that movement to more equal rates does not justify AIU's increased revenue allocation to the DS-5 class. AIU counters that Staff's approach does not provide sufficient weight to the lighting incremental cost study, ignores LGI's pleas that Fixture Charges be brought closer together, and does not adequately address the Commission's inquiries from AIU's prior rate order about moving Fixture Charges closer together. Movement toward uniform Fixture Charges across the three companies, using the incremental cost study as a guide, makes sense according to AIU because of outside vendors compete against its standard fixture offerings. Movement toward uniform Fixture Charges also makes sense, AIU adds, because there is no difference among the three companies in the incremental costs of providing a fixture.

Staff further claims that by not setting each individual company's DS-5 revenue allocation target at the level to achieve an equal return, AIU's method is arbitrary and unfair. In response, AIU asserts that its DS-5 revenue allocation approach is methodical, with the ultimate goal of recovering the cost of service at an equal return from the combined DS-5 classes of the three companies in a future case. The goal at this time, AIU explains, is to make progress toward uniform rates by easing AmerenIP rates lower and AmerenCIPS rates higher. Since each company is a single legal entity, AIU states that any revenue excess or deficiency still needs to remain within the individual utility, and should be absorbed by other rate classes.

Thus, by adopting its approach, AIU contends that the Commission would not be abandoning cost-based ratemaking. To the contrary, AIU argues, it would reflect the recognition that moving toward a uniform pricing approach that uses the incremental cost study as a guide, but ultimately constrained to the total embedded cost of service for all three utilities combined, is a sound policy choice.

c. Staff Position

Staff prefers its own rate design for the DS-5 lighting class over AIU's. Staff states that its approach would revise AIU's proposed lighting rates for each company on an equal percentage basis to conform to Staff's recommended revenue allocations for the lighting classes. Staff contends that its approach will best ensure that lighting customers only pay their fair share of system costs.

AIU argues that Staff's proposed lighting rates are flawed because they are derived from current DS-5 rates and therefore ignore the discussion of bringing Fixture Charges closer together. Staff responds that AIU is incorrect and asserts that the starting point for Staff's proposed DS-5 rates is AIU's proposed rate design which incorporates movement toward more equal charges. Staff adds, however, that such movement must be balanced with an allocation of the revenue requirement that is equitable to all rate classes. Staff asserts that its proposed revenue allocations are fair to all rate classes and its rate design for the lighting class is reasonable as well.

d. Commission Conclusion

The Commission recognizes that AIU is in a difficult situation in which it is working toward uniform lighting rates among the three electric utilities as encouraged by the Commission while at the same time trying to keep in mind the cost of service. At the outset, the Commission needs to clarify that it does not necessarily expect Fixture Charges to someday be identical across the three electric utilities. The directive that the Commission gave AIU in its last rate proceeding for its next (this) rate proceeding is "to address the possibility of moving the light fixture charges toward a more similar charge among AmerenCILCO, AmerenCIPS, and AmerenIP." (Docket Nos. 07-0585 et al (Cons.), Order at 359) The Commission does not want to give AIU the impression that it expects AIU to "force" identical Fixture Charges into the DS-5 tariffs even if legitimate cost of service reasons warrant different treatment. The direction given to AIU in its last rate proceeding is consistent with this message.

That being said, it appears to the Commission that AIU earnestly attempted to comply with the Commission's directive in the last rate proceeding. By considering both the results of its incremental COSS and embedded COSS, AIU appears to be trying to move the Fixture Charges closer to together while bearing cost of service in mind. The Commission recognizes that the numbers are apt to change after AIU reruns the COSS, but nevertheless finds the methodology reasonable for the DS-5 class for purposes of this proceeding. In contrast, it is not clear to the Commission how Staff's approach is designed to move the Fixture Charges closer. Accordingly, the Commission accepts AIU's position on this issue for purposes of this proceeding.

5. Combined Billing of Multiple Meters

a. IIEC Position

IIEC proposes a modification to AIU's Standards and Qualifications for Electric Service, so that combined billing of multiple meters, on the same or adjacent premises, would be permitted. Currently, the combined billing of multiple meters on the same or adjacent premises is not permitted, except for those customers having agreements with AIU or having the benefit of tariff provisions permitting same prior to January 2, 2007. AmerenIP previously permitted such combined billing.

IIEC asserts that AIU's current policy has several adverse implications for larger customers. Among the implications, IIEC asserts, is the fact that it creates more customer accounts than are necessary and increases AIU's customer charge revenue. IIEC adds that it reduces the beneficial impact of diversity in separately metered loads of a single customer in a single location on the Distribution Delivery Charge. The current tariff provisions, IIEC continues, also effectively create a barrier to the development of combined heat and power ("CHP") installations under certain circumstances.

With regard CHP installations, IIEC explains that industrial customers with a number of processes under one account proposing to construct a CHP or cogeneration plant on an adjacent site would be required to treat the CHP plant as a separate account from the remainder of the customer's load served by the CHP facility. According to IIEC, such a customer would not be able to enjoy the benefit of using the output of its CHP plant to reduce the amount of electricity delivered to other production facilities in the same plant, but on adjacent premises. IIEC further asserts that to the extent the power generated by the CHP unit is cheaper than power available in the market, the owner would not be able to replace the more expensive power with the cheaper CHP unit power at its adjacent facilities. IIEC also contends that AIU's policy becomes a barrier to CHP development if AIU begins collecting the PURA tax through a cent per kWh charge. Under such circumstances, the customer would pay the full PURA tax on all of the separate accounts at its plant without offset for the power generated by the CHP plant. If the generator output is not included within the same account as the plant load, IIEC complains that the customer would pay the PURA tax on the full plant load even though the net effect of the new generator is to reduce the amount of energy the utility needs to deliver to the customer for its entire manufacturing plant or possibly to the utility system as a whole.

While IIEC acknowledges that CHP units have still been developed in AIU's service territory, IIEC argues that that fact does not address the fundamental problem with AIU's policy, which discourages CHP units on a going-forward basis. IIEC also maintains that spending significant sums to reconfigure electrical distribution systems to accommodate a new CHP plant is not a satisfactory solution to the problem. Customers of this kind, IIEC contends, should not be forced to expend large sums of capital on reconfiguring electrical distribution system in order to provide a source of power and energy that is a preferred source of power and energy for Illinois, when a simple change to AIU's tariffs will accommodate the construction of the CHP unit without such expenditures. IIEC references Section 16-115D(h) of the Act in support of its assertion that Illinois law encourages CHP installations.

IIEC finds little reassurance in AIU's statement that its tariffs allow 40 kW and over cogenerators to reduce their Distribution Delivery Charge through net metering. IIEC points out that under Section 16-107.5 of the Act, net metering is not available to generating units with a rated capacity greater than 2,000 kW. IIEC asserts that eligible units are relatively small, and would be hardly comparable to the CHP or other cogeneration units that may be built by a large manufacturing customer to serve the load at its manufacturing facility, which may be much larger than 2,000 kW of electrical demand. Furthermore, IIEC points out that AIU has also apparently overlooked the provisions of the net metering legislation which limits the applicability of the law to retail customers owning or operating a "solar, wind or other renewable electrical generating facility." (220 ILCS 5/16-107.5(b)) The Act further defines "renewable generating facility" to mean a facility powered by "solar electric energy, wind, dedicated crop for energy generation, anaerobic digestion of livestock or food processing waste, fuel cells or micro turbines powered by renewable fuels, or hydroelectric energies." (Id.). IIEC asserts that a large cogenerating unit at a steel manufacturing facility, for example, fueled by something like coke oven gas or fuels other than those mentioned, would not benefit from AIU's net metering tariffs.

To the extent that a customer seeks other benefits associated with distributed generation, AIU notes that Rider QF provides two different compensation options that provide the customer with a fair market value for the output of its generating unit. IIEC observes, however, that this applies only to the energy value of the generating unit, and does not address the recovery of delivery service costs generally, or the PURA tax specifically from these customers, without giving them credit for their cogeneration.

In response to AIU's billing determinants argument, IIEC asserts that AIU fails to recognize that if the CHP facility were simply located on the customer's premises, behind the meter, the reduction in billing demands would be the same whether the CHP unit was located on or adjacent to the customer's premises. IIEC states that locating a CHP facility on an adjacent property rather than on its main plant property may be due to circumstances largely beyond the customer's control (e.g., a bisecting roadway), and it should not be penalized simply due to such circumstances.

Lastly, AIU argues that IIEC has not proposed any specific tariff language to be reviewed by the Commission. IIEC points out that its recommendation is that AIU be required to change its policy. Presumably, if the Commission follows IIEC's recommendation, AIU would present the tariff language necessary to accomplish that change in policy. IIEC also notes that until recently, AmerenIP had provisions in its Standard Terms and Conditions which addressed IIEC's concerns. IIEC does not believe it would be difficult for AIU to develop, or simply modify and reuse, the prior language to achieve the change in policy directed by the Commission.

b. AIU Position

In response to IIEC's concerns, AIU recognizes that the existence of more than one service point results in a corresponding increase in the number of Customer Charges assessed on the customer. What IIEC fails to consider, AIU counters, is that for customers metered at primary voltage or greater, a substantial portion of the cost basis for the Customer Charge is for the current and/or potential transformers used to meter the customer. Since metering has been unbundled, the Commission has directed that current and potential transformers associated with metering remain part of the utility's responsibility. AIU states that customers are assessed a monthly Customer

Charge in lieu of a lump sum payment predominantly to pay for the current and/or potential metering facilities. According to AIU, the added revenue offsets the added cost.

AIU also agrees with IIEC that its policy may diminish a possible reduction in the Distribution Delivery Charge for the customer if it was allowed to combine all service points for billing purposes. AIU asserts, however, that IIEC fails to recognize that AIU's tariffs already provide generators with the ability to mitigate their Distribution Delivery Charges. AIU explains that under Section 16-107.5 of the Act, non-residential customers with generators with a name plate capacity rating in excess of 40 kW are assessed delivery service charges based on a "gross" method, where the amount of generation is not allowed to serve as an offset to delivery service charges. Those customers operating on-site generators with capacities under 40 kW are allowed to offset distribution charges. Under Rider QF, however, a customer with a CHP facility with output that exceeds the load at a service point for the entire month would avoid Distribution Delivery Charges, even though facilities were designed and built to ensure adequate distribution capacity is available to serve the customer in the event their generation facility became unavailable for any period of time. AIU states that this practice has been in place for several years, and pre-dates the establishment of net-metering in Illinois.

Essentially, AIU continues, the energy and demand associated with load are registered by the meter, in a manner inclusive only to the extent required beyond what is provided by the generator. AIU allows all customers with facilities up to 1 megawatt to avail themselves of this benefit pursuant to longstanding tariff policies. Beyond that point, AIU requires that generation be separately metered. Further, AIU states that the customer must interconnect the generator directly to the system, or else they can not receive the load off-setting benefits of the Rider QF option, described above. Customers that choose to have AIU run a separate distribution line to the facility will be required to have the interconnected facilities metered after installation of the load-serving line segment.

Additionally, to the extent a customer is metered at the generator, and assessed a delivery service change for all customer load, AIU notes that under the current Rider QF, the customer may choose to be compensated under a fixed or variable rate. AIU states that such compensation will provide some level of total bill offset, even providing compensation in excess of supply charges assessed in certain circumstances. Thus, between net metering and its established policy for onsite generation for Rider QF customers, AIU believes that it allows for significant flexibility for large customers pursuing on site generation supply options. AIU asserts that any expansion of these options to include additional aggregation of metering data for billing purposes is not cost-based, and ultimately would increase the cost responsibility borne by other customers.

Moreover, AIU states that Section 16-107.5 provides that non-residential customers taking service under a net-metering election at a level greater than 40 kW are required to pay distribution charges and taxes for their delivered power. AIU maintains that the policy implications of this legislative prerogative would bode against the revision of Rider QF policies in a manner that would further reduce delivery service and other charges, such as taxes and energy efficiency rider revenues.

With regard to IIEC's concerns over CHP installations, AIU reiterates that current tariff provisions allow customers a reasonable opportunity to achieve the same end that IIEC advocates. For customers that do not qualify, or elect to receive service pursuant to Rider NM - Net Metering Service, Rider QF provides two compensation options for customers that produce more power than they use: fixed-price and variable-price compensation. AIU states that both compensation methods reflect a fair market value for the qualifying facility output. AIU adds that customers that are unhappy with the Rider QF options may take their power output directly to MISO and register their generator as a resource. In AIU's view, customers have both physical and financial options that allow them to effectively reduce their electricity costs using their CHP facility.

From a broader policy perspective, AIU notes that its tariff provisions related to metering and cogeneration are tailored to comply with applicable laws and regulations, as well to avoid unnecessary subsidization from other customer classes. AIU believes that removing any undue barriers to supply options, including self-supply by means of distributed generation, is a goal worthy of consideration. AIU states that its current policy, however, of allowing one meter per service point more closely aligns distribution service cost recovery with those who cause the cost. Measurement of energy on a per service point basis, AIU continues, is a foundational step to associating energy consumption costs with the facilities and customer behind the delivery point.

Finally, AIU states that its billing determinants have not been reviewed in order to determine the impact of implementing IIEC’s proposal. AIU points out that there is at least one large CHP facility which recently began operating in AmerenIP's service area. A change to the metering policy would effectively reduce the billing demands shown in the test year billing determinants, and thus reduce AmerenIP’s expected revenue. AIU adds that the prices to other customers would need to be increased to recover the authorized revenue requirement. Because no party has performed such analysis, AIU maintains that IIEC’s recommendation should be rejected. Additionally, AIU indicates that any new tariff language would need to be developed and reviewed in the same way that other tariff changes were reviewed in this case. Since the IIEC has not proposed any such tariff language for review by parties in this docket, AIU states that there is nothing for the Commission to review.

c. Commission Conclusion

Having considered the record, the Commission finds merit in IIEC's position. Despite AIU's arguments to the contrary, the Commission is persuaded that combined billing of multiple meters, on the same or adjacent premises, should be permitted. AmerenIP apparently even allowed combined billing until relatively recently. AIU's reliance on Section 16-107.5 of the Act is misplaced, as it is not even applicable to the situation at hand. Similarly, Rider QF, while applicable to CHP and other cogeneration facilities, is not relevant to the question of combined billing.

To the extent that the current tariff provisions impede the development of industrial cogeneration projects, the Commission views the elimination of such hindrances as a side effect of permitting combined billing. If the practicality of combined billing also facilitates cogeneration projects that are consistent with Illinois policy, the Commission considers that outcome fortuitous and encourages customers to take advantage of such opportunities.

While the Commission finds that combined billing is appropriate, the Commission is hesitant to direct AIU to prepare tariffs allowing such as part of its compliance tariff filing at the conclusion of this proceeding. Determining language implementing combined billing may not be as straightforward as IIEC suggests. Therefore, to avoid any complications associated with AIU's final tariffs as well as any unforeseen rate or rate design problems, the Commission refrains from directing AIU to implement combined billing in this proceeding. Instead the Commission directs AIU to work with IIEC, Staff, and any other interested parties to develop tariffs addressing the concerns of those involved. Whether tariffs permitting combined billing of multiple meters, on the same or adjacent premises, can be agreed upon or not, AIU should include such tariff provisions with its next electric rate case filings. If the tariff language is not agreed upon, interested parties are free to litigate the issues. Those objecting to AIU's language, however, should submit alternative language for the Commission's consideration.

6. Rate Limiter

Both the DS-3 and DS-4 rate classes currently contain rate limiter provisions that ensure the monthly charges for the sum of Distribution Delivery and Transformation Charges are limited to no more than a set ¢/kWh value if 20% or less of the customer’s annual usage occurs in the summer months of June through September. The limiter value is presently 1.953 ¢/kWh for AmerenCILCO, 2.223 ¢/kWh for AmerenCIPS, and 2.613¢/kWh for AmerenIP. The limiter values do not differ between the DS-3 and DS-4 rate classes. The rate limiter provisions were implemented through the Order in Docket No. 07-0165. At that same time, DS-3 and DS-4 Distribution Delivery Charges were increased to maintain revenue neutrality.

a. GFA Position

AIU proposes to constrain the increase in delivery service rates to 23.5% for AmerenCILCO, 19.5% for AmerenCIPS, and 21.8% for AmerenIP. GFA complains, however, that AIU has proposed higher increases to the rate limiters than are proposed for the respective rate classes. GFA argues that AIU's proposal in this proceeding disproportionately impacts grain companies. According to GFA, at least one grain company will experience a delivery service rate increase as high as 42%. GFA recommends that the rate limiters be constrained by the same percentage as the constraints that are applicable to the respective rate classes. GFA contends that this approach more closely tracks the approach taken by the Commission in AIU's previous rate proceeding, Docket Nos. 07-0585 et al (Cons.), where the Commission approved an across-the-board increase to the rate limiters, thereby treating the rate limiter customers the same as other customers.

GFA acknowledges that both the Commission and AIU have recognized the need to reduce and eliminate the rate limiters at the appropriate time, but maintains that now is not the time. GFA contends that the time to consider eliminating the rate limiters is when AIU files a rate case based on a class COSS, and proposes a fully cost-based rate design. While AIU filed a class COSS in this proceeding, GFA states that AIU deviated from it in designing its proposed rates. GFA adds that various parties have advocated differing allocators in this case as well (e.g. CP vs. NCP). Until the Commission has reviewed and determined the appropriate allocators to be used in a full class COSS rate case, with due consideration of seasonal rates, GFA asserts that it will not be known whether and to what extent rates are fully cost justified. Without that knowledge, GFA contends that the Commission will not know in which direction and to what degree rates should be adjusted to eliminate the rate limiters.

b. AIU Position

AIU proposes to retain the rate limiter provision, but increase the limiter ¢/kWh amounts to a level so that the total dollar rate limitation effect is approximately the same under proposed rates as it is under present rates. AIU proposes to set the limiter value at 3, 3, and 4¢/kWh for AmerenCILCO, AmerenCIPS and AmerenIP customers, respectively. Upon learning the final revenue requirement, AIU states that it will need to recalculate the rate limiter values as part of developing the final rates in these cases.

GFA, on the other hand, proposes to limit the increase to the ¢/kWh rate limiter at the same level as the class average increase. AIU opposes GFA's proposal and argues that an adjustment to the rate limiter by an amount only equal to the class average increase would not allow for the eventual reduction or elimination of the provision, but instead would further increase the subsidy provided to eligible customers. AIU adds that applying its method for conforming rates to the final revenue requirement by decreasing the DS-3 Distribution Delivery Charges (and holding the other charges as proposed) will place downward pressure on the ¢/kWh rate limiter values, which is a benefit to GFA.

c. Staff Position

Staff supports AIU's approach to the rate limiters in this proceeding. Staff observes that AIU's proposals in this case include constraints on revenue increases for individual rate classes as well as continued efforts to limit adverse impacts for large non-summer users in the DS-3 and DS-4 classes. Staff therefore believes that it would be consistent with these efforts to maintain the rate limiters. Also, consistent with the Commission's past pronouncement that the rate limiters are temporary, Staff notes that

AIU's proposal facilitates the future elimination of the rate limiters and placement of the larger customers currently under the rate limiter under the same tariffs that apply to other DS-3 and DS-4 customers.

d. IIEC Position

IIEC does not oppose the continuation of the rate limiters in this case, as it has proposed rate moderation/mitigation measures of its own. IIEC notes, however, the apparent inconsistency between AIU's support for the rate limiters for the benefit of grain drying customers, but apparent lack of concern for other large customers. Without the continuation of the rate limiters, IIEC understands that some of AIU's grain drying customers would experience delivery service rate increases as high as 42%. IIEC states that this must be contrasted with increases in delivery service rates as large as 1,000% for some of AIU's largest customers who do not happen to be grain dryers. IIEC views this disparity as further support for its position that AIU has been trying to shift costs away from smaller customers for public relations and political reasons.

e. Commission Conclusion

All of the parties agree that now is not the time to eliminate the rate limiters. The only issue in dispute is how to modify the existing rate limiters to reflect the change in electric delivery service rates. AIU proposes to increase the limiter ¢/kWh amounts to a level so that the total dollar rate limitation effect is approximately the same under the new rates as it is under present rates. GFA recommends that the rate limiters be constrained by the same percentage as the constraints that are applicable to the respective rate classes.

Having considered the arguments, the Commission finds AIU's proposal more in tune with the ultimate goal of eliminating the rate limiters. Specifically, AIU's proposal takes steps toward that goal while GFA's proposal essentially maintains the status quo. While GFA talks about eliminating the rate limiters, its proposal as well as the "conditions" that it believes are necessary before doing so seem geared more toward delaying elimination of the rate limiters. GFA seems to suggest that the Commission must have an undisputed class COSS underlying strictly cost based rates before it can eliminate the rate limiters. Such a scenario would be very rare.

Because it finds AIU's proposal a step toward the goal of someday eliminating the rate limiters, the Commission adopts it for purposes of this proceeding. The Commission agrees with AIU that upon learning the final revenue requirement, AIU will need to recalculate the rate limiter values as part of developing the final rates in these cases. That is why the Commission is approving AIU's methodology and not the specific ¢/kWh amounts AIU identified in its testimony.

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, 2008, 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, 2008, as adjusted, is $308,866,000;

(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, 2008, as adjusted, is $532,492,000;

(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, 2008, as adjusted, is $1,463,178,000;

(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, 2008, as adjusted, is $195,006,000;

(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, 2008, as adjusted, is $200,191,000;

(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, 2008, as adjusted, is $526,999,000;

(11) a just and reasonable return which AmerenCILCO should be allowed to earn on its net original cost electric delivery service rate base is 8.05%; this rate of return incorporates a return on common equity of 9.9%;

(12) a just and reasonable return which AmerenCIPS should be allowed to earn on its net original cost electric delivery service rate base is 8.02%; this rate of return incorporates a return on common equity of 10.06%;

(13) a just and reasonable return which AmerenIP should be allowed to earn on its net original cost electric delivery service rate base is 8.97%; this rate of return incorporates a return on common equity of 10.26%;

(14) a just and reasonable return which AmerenCILCO should be allowed to earn on its net original cost gas delivery service rate base is 7.83%; this rate of return incorporates a return on common equity of 9.4%;

(15) a just and reasonable return which AmerenCIPS should be allowed to earn on its net original cost gas delivery service rate base is 7.59%; this rate of return incorporates a return on common equity of 9.19%;

(16) a just and reasonable return which AmerenIP should be allowed to earn on its net original cost gas delivery service rate base is 8.59%; this rate of return incorporates a return on common equity of 9.4%;

(17) the rate of return for AmerenCILCO set forth in Finding (11) results in base rate electric delivery service operating revenues of $127,501,000 and net annual operating income of $24,864,000 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 $261,265,000 and net annual operating income of $42,705,000 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 $496,268,000 and net annual operating income of $131,247,000 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 $69,392,000 and net annual operating income of $15,269,000 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 $73,676,000 and net annual operating income of $15,195,000 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 $166,724,000 and net annual operating income of $45,343,000 based on the test year approved herein;

(23) the electric delivery service rates AmerenCILCO, AmerenCIPS, and AmerenIP as well as the gas delivery service rates of AmerenCIPS 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 gas delivery service rates of AmerenCILCO and AmerenIP 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 $127,501,000, which represents an increase of $5,504,000 or 4.51%; 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 $261,265,000, which represents an increase of $25,888,000 or 11.00%; 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 $496,268,000, which represents an increase of $34,316,000 or 7.43%; 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 $69,392,000, which represents a decrease of $5,686,000 or (7.57%); 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 $73,676,000, which represents an increase of $501,000 or 0.68%; 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 $166,724,000, which represents a decrease of $4,467,000 or (2.61%); 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) the new tariff sheets authorized to be filed by this Order shall reflect an effective date not less than five working days after the date of filing, with the tariff sheets to be corrected within that time period if necessary, except as is otherwise required by Section 9-201(b) of the Act as amended; 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 June 5, 2009 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 June 5, 2009, 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.

DATED: February 25, 2010

Briefs on Exceptions must be received by March 11, 2010.
Briefs in Reply to Exceptions must be received by March 18, 2010.

John D. Albers
J. Stephen Yoder
Administrative Law Judges