STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Central Illinois Light Company	:	
	:	02-0837
Proposed general increase in natural gas rates.	:	

INITIAL BRIEF OF THE STAFF OF THE ILLINOIS COMMERCE COMMISSION

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NOW COMES the Staff of the Illinois Commerce Commission ("Staff"), through its attorneys, and files its Initial Brief in the above-captioned proceeding.

I. INTRODUCTION

A. Background

Pursuant to Article IX of the Public Utilities Act ("PUA" or "Act"), on November 22, 2002, Central Illinois Light Company d/b/a Ameren CILCO ("CILCO" or "Company") filed, with the Illinois Commerce Commission ("Commission"), tariff sheets setting forth the Company's proposal to increase base rates for natural gas service. The tariff filing was accompanied with testimony. The Commission entered a Suspension Order on December 11, 2002 and a Resuspension Order on April 20, 2003.

B. Procedural History

Pursuant to proper notice, a Prehearing Conference was held in this matter before duly authorized Administrative Law Judge of the Commission in Springfield, Illinois on January 8, 2003. At the Prehearing Conference, the Judge set a schedule which provided for the filing of Staff and Intervenor direct, Company rebuttal, Staff and Intervenor rebuttal and Company surrebuttal testimonies as well as hearings and Initial and Reply Briefs.

Petitions to Intervene were filed by Illinois Industrial Energy Consumers ('IIEC"), the People of the State of Illinois ("People"), Citizens Utility Board ("CUB") (People and CUB collectively ("C&GI"), and Business Energy Alliance and Resources LLC ("BEAR"). All Petitions to Intervene were granted.

Evidentiary hearings were held at the Commission's Springfield offices on June 10 through June 13, 2003. Appearances were entered on behalf of CILCO, the People, CUB, IIEC, BEAR, and Staff. Stephen D. Underwood, Robin L. Turner, Vickiren S. Bilsland, Raymond J. Stillson, Vonda K. Seckler, Michael J. Getz, Jonathon A. Lesser, Michael Austin, Michael G. O'Bryan and C. Kenneth Vogl provided testimony on behalf of CILCO.[1] Bonita A. Pearce, Dianna Hathhorn, Rochelle Phipps,, Cheri L. Harden, Eric Lounsberry, and Charles C. S. Iannello provided testimony on behalf of Staff. BEAR witness Lee Smith, the People and CUB witness David J. Effron and IIEC witness John W. Mallinckrodt also provided testimony. At the conclusion of the June 13, 2003 hearing, the record was marked "Heard and Taken."

C. Nature of Operations

CILCO owns and operates natural gas distribution systems in Illinois.

D. Test Year

The Company proposed a historical test year of 2001 with known and measurable changes. There were no objections to the Company's proposal.

II. RATE BASE

[1] The testimony of Nagendra Subbakrishna, offered by CILCO as rebuttal testimony was stricken upon the motions of the People and Staff.

A. Uncontested Issues

1. Adjustment to Customer Deposits

Staff witness Pearce proposed an adjustment to Customer Deposits to reflect in the Company's test year rate base the 13-month average balance of customer deposits rather than the year-end balance that was reflected by the Company in its filing. (Staff Ex. 1, Sch. 1.10) The Company accepted Staff's adjustment (CILCO Ex. 6.2, p. 3) Since the Company reflected the effect of Staff's adjustments in its rebuttal position revenue requirement, Staff Exhibit 7R, Schedule 7.10 reflects no adjustment to rate base.

Staff's adjustment to Customer Deposits was adopted by the Company in its rebuttal position revenue requirement and is uncontested.

2. Adjustment to Budget Payment Plan Balances

Staff witness Pearce proposed an adjustment to remove from rate base a portion of Budget Payment Plan Balances to reflect a 13-month average versus the 12-month average that was reflected by the Company in its filing. (Staff Ex. 1, Sch. 1.11) The Company accepted Staff's adjustment. (CILCO Ex. 6.2, p. 3 and CILCO Ex. 6.6, p. 2 of 2) Therefore, ICC Staff Exhibit 7R, Schedule 7.11 reflects no additional adjustment to rate base.

Staff's adjustment to Budget Payment Plan Balances was adopted by the Company in its rebuttal position revenue requirement and is uncontested.

3. Adjustment to AM/FM Gas Mapping Pro Forma and Related Amortization Expense

Staff witness Pearce proposed an adjustment to remove from rate base a portion of the Company's pro forma adjustment for post-test year plant additions related to the AM/FM Gas Mapping project on the basis that it was not known and measurable. (Staff Ex. 1, Sch. 1.8) However, based on additional information provided by the Company in support of the 2003 amounts, Staff withdrew its proposed adjustment. Therefore, the amounts of Staff's pro forma adjustment for AM/FM Gas Mapping, shown on ICC Staff Exhibit 7R, Schedule 7.8, match the amounts reflected by the Company in its filing.

Staff's adjustment to the AM/FM Gas Mapping project was withdrawn in rebuttal testimony. (Staff Ex. 7R, p. 6)

4. Common Plant

AG/CUB witness Effron proposed an adjustment to reduce the rate base by $1,842,000 (AG/CUB Ex. 1.0, Sch. B-1), in accordance with the allocation percentage used by the Company in its last gas rate case. In that proceeding (Docket No. 94-0040), CILCO allocated 50% of account 303, Customer Information System and 40% of all other common plant accounts to the gas business. (AG/CUB Ex. 1.0, p.5) In the instant proceeding, CILCO allocated common plant 45% to gas operations in its initial filing, in accordance with the percentage that resulted from the 2000 DST case. (CILCO Rebuttal Ex. 6.2, pp. 8-9) Subsequent to filing, the Company discovered an error in its application of the 45% allocation methodology. (CILCO Ex. 6.2, p. 9) In an effort to correct the known error and locate additional errors of a similar nature, the Company re-allocated common plant using the same line item allocation factors used in the 2000 DST case (instead of using the flat 45% factor reflected in the initial filing). (CILCO Ex.

6.2, p. 9) The revised methodology produced an overall allocation of approximately 43% of common plant to the gas business.

Based on the Company's revision, Staff proposed no adjustment to the Company's allocation of common plant. AG/CUB witness Effron made no further comment regarding the common plant allocation after the Company described its revision in CILCO Exhibit 6.2.

AG/CUB witness Effron's proposed adjustment to common plant is no longer contested because the Company revised its allocation in rebuttal testimony. (CILCO Ex. 6.2, pp. 9-11, and CILCO Ex. 6.3) The Company reflected the modification of common plant allocated to the gas business in CILCO Exhibit 6.6, page 2 of 2, the Company's rebuttal position revenue requirement.

5. Accumulated Deferred Income Taxes

AG/CUB witness Effron proposed an adjustment to exclude debit balances (AG/CUB Ex. 1.0, pp. 9–10) related to pensions from the accumulated deferred income tax balance that was included by CILCO in its Revised Schedule B-5.2. CILCO accepted Mr. Effron's proposed adjustment in CILCO Exhibit 6.2, page 2 and CILCO Exhibit 6.6, page 1 of 2 (the Company's rebuttal position revenue requirement). Staff proposed no additional adjustments to accumulated deferred income taxes, therefore, Mr. Effron's adjustment is reflected in the Company Rebuttal Pro Forma Rate Base, column (b) on Schedule 1.3, page 1 of 2 of Appendix A, attached hereto.

AG/CUB witness Effron's proposed adjustment to eliminate the accumulated deferred income tax balances related to pensions is no longer contested since the Company reflected his adjustment in rebuttal testimony. (CILCO Ex. 6.6, p. 1 of 2)

6. Original Cost Determination

Staff requested that the Commission include certain language in this proceeding's order regarding original cost determination. (Staff Ex. 1, p. 12) The language included therein incorrectly referred to a schedule prepared by Staff. The correct reference should have been a CILCO schedule. For this reason, Staff recommends that the Commission substitute the following language in lieu of that which was recommended on Staff Ex. 1, p.12:

> It is further ordered that the original cost of plant at December 31, 2001, as reflected on CILCO Section 285.2005 Schedule B-1 is unconditionally approved as the original cost of plant for consideration of 83 Ill. Adm. Code 510.

7. Depreciation Study Recommendation

Staff reviewed the Depreciation study completed by American Appraisal Associates based on plant and reserve balances at December 31, 1991. (Staff Ex. 1, pp. 13-14) Since depreciation expense has one of the largest impacts on the Company's net income, revenue requirement, and rate base, it is important that these rates be appropriate. Staff did not propose any changes at the present time. However, since it has been 11 years since the Company's previous study was performed, Staff requests that the Commission direct the Company to perform a depreciation study prior to its next electric or gas rate proceeding. Staff recommends that depreciation studies submitted to the Commission to support future electric and gas rate proceedings be no more than five years old. Staff notes that the Commission has required other utilities to conduct depreciation studies. In Docket No. 95-0032, order dated November 8, 1995, the Commission placed the Peoples Gas Light and Coke Company on a five-year schedule for conducting its depreciation study. Additionally, in Docket No. 89-0276, order dated June 6, 1990, Illinois Power Company was ordered to perform a depreciation study prior to its next electric rate case.

CILCO did not take exception to Staff's recommendation regarding future depreciation studies. (CILCO Ex. 6.2, p. 3)

Staff recommends that the Commission, in the Findings and Orderings paragraph of the order in this proceeding, direct the Company to perform a depreciation study prior to its next electric or gas rate proceeding. Staff further recommends that depreciation studies submitted to the Commission to support future electric and gas rate proceedings be no more than five years old.

B. Contested Issues

1. Adjustment to YTD September 2002 Gas Plant Additions and Related Depreciation Expense

Staff's position is that AG/CUB witness Effron's proposed adjustment to disallow all post-2001 pro-forma plant additions (AG/CUB Ex. 1.0, Sch. B) should be accepted by the Commission. Staff bases this conclusion on the fact that the net plant in service balance at the end of 2002 is lower than the net plant in service balance at the end of 2001, the historic test year selected by the Company.

Staff witness Pearce analyzed the various post-test year pro forma plant additions that were proposed by the Company in its filing, as allowed under Part 285. As a result of this analysis, Staff proposed an adjustment to remove from Rate Base certain post-test year plant additions that were duplicated by the Company in its filing. (Staff Ex. 1, Sch. 1.7) The Company accepted Staff's proposed adjustment (CILCO Ex.

6.2, p. 4) Since the Company reflected the effect of Staff's adjustments in its rebuttal position revenue requirement, ICC Staff Exhibit 7R, Schedule 7.7 reflects no further decrease to rate base.

However, AG/CUB witness Effron opposed the Company's pro forma adjustment to increase rate base for post-test year additions of $14,139,000 (CILCO Section 285.2015, Sch. B-2.1) less $821,000 of related accumulated depreciation (CILCO Section 285.2050, Sch. B-3.1), in its entirety ($13,318,000 effect on net plant in service) because the Company's net plant in service balance at December 31, 2002 was lower than the net plant in service balance at December 31, 2001. (AG/CUB Ex. 1.0, pp. 5–9 and Sch. B) Mr. Effron states that the Company's pro forma adjustment to include post-test year plant additions should be disallowed because it is one-sided, in that it does not recognize other changes that will be taking place after the end of the test year that will tend to offset the revenue requirement effect of the additions to plant in service. In particular, Mr. Effron points out, although the Company recognizes the increase in accumulated depreciation directly related to the pro forma plant additions, it does not recognize the growth in accumulated depreciation on embedded plant in service that will be taking place as the new plant additions are going into service. Mr. Effron points out that based on the Company's actual experience, this growth in the accumulated depreciation reserve will more than offset the increase in revenue requirements associated with the additions to plant in service. (AG/CUB Ex. 1.0, p. 7, and Sch. B-1.1) Mr. Effron recommends that the Commission reject the Company's proposed pro forma adjustment to increase the 2001 historic test year plant in service balance for post-test year additions on the basis that this is not a known and measurable change—rather it is a selective use of one isolated element of a forecasted test year. As such, he states, the Company's adjustment should not be incorporated into the Commission's determination of rate base revenue requirements, especially in circumstances where the Company's rate base is not growing over time (AG/CUB Ex. 1.0, pp. 7–9)

CILCO opposes Mr. Effron's proposed disallowance of all post-test year pro forma plant additions noting that Part 285 allows a utility to elect to use a historical or a future test year and the Company elected to use a historical test year in this proceeding. (CILCO Ex. 6.2, pp. 5-7) The Company further points out that Part 285 allows the utility to adjust the historical test year to include known and measurable changes occurring within 12 months from the filing date of the new tariffs. CILCO avers that Mr. Effron's proposal would nullify this provision. Furthermore, the Company states that Mr. Effron's proposal would deprive it of an opportunity to earn a return on actual plant additions that have been made as of September 30, 2002, as well as known and measurable additions that will be made before the final order is entered in this docket. The Company points out that Mr. Effron does not address specific capital additions that occur after the test year—he simply proposes to exclude them because they occurred after the 2001 historical test year. The Company notes that it responded to numerous data requests from Staff seeking information on the post-test year plant additions and provided supporting documentation for the additions, including those that have already been placed in service. The Company further points out that Staff appears satisfied that the Company has met its burden of proof regarding the proposed additions. CILCO Ex. 6.2, pp. 6–7) The Company also argues that Mr. Effron's reasoning that the additions should be excluded because the test year is not adjusted to include depreciation that occurs after the test year is a further violation of the test year rules under Part 285. The Company states that if Mr. Effron's proposal were adopted it would effectively convert the 2001 historic test year to a future test year. (CILCO Ex. 6.9, p. 3)

Staff notes that both CILCO and AG/CUB witness Effron make valid arguments related to this issue. The Company is correct that it may choose a historical test year and propose pro forma adjustments to reflect known and measurable changes in plant investment where such changes occur or are reasonably certain to occur subsequent to the test year within 12 months from the filing date of the new tariffs. Whether the post-test year pro forma additions, after giving effect to Staff witness Pearce's adjustment to eliminate duplicative post-test year plant additions (Staff Ex. 7R, Sch. 7.7), occurred is not at issue. However, the Commission must decide if the information presented by the Company in accordance with Part 285 adequately supports its requested tariffs. Staff believes the Commission should look beyond the requirements of Part 285 to the issue at hand. Regardless of the type of information the Company is allowed or even required to present, the most compelling support for Mr. Effron's proposed disallowance of post-test year plant additions is based on actual experience. The net plant in service balance at the end of the 2001 historical test year appears to be more representative of net plant in service when the rates go into effect. (AG/CUB Ex. 1.0, Sch. B-1.1) For this reason, Staff has incorporated the impact of AG/CUB witness Effron's proposed adjustment to disallow all post-2001 pro forma plant additions into the Revenue Requirement attached to this Brief. (See Appendix A, Sch. 1.7)

Staff recommends that the Commission accept AG/CUB witness Effron's proposed adjustment to disallow all post-test year pro forma plant additions, as reflected in Appendix A, Schedule 1.4, page 2 of 2.

2. Adjustment to Materials and Supplies Inventory

Staff's position is that the Commission should accept Staff's proposed adjustment to reduce materials and supplies inventory by the associated accounts payable.

Staff witness Pearce proposed an adjustment to correct an error in the average balance of materials and supplies inventory and to reduce the Company's test year materials and supplies inventory by the associated accounts payable. (Staff Ex. 1, p. 8 and Sch. 1.9) The Company corrected the error in the average balance of materials and supplies inventory in its Errata to Part 285 Standard Filing Requirements, through Revised Schedule B-5.1. However, the Company did not accept Staff's adjustment to reduce the average materials and supplies inventory balance for a related portion of accounts payable because it believes the adjustment is only appropriate in the context of a complete cash working capital analysis. (CILCO Ex. 6.2, p. 11)

Staff notes, however, that Cash Working Capital is a separate component of Rate Base, distinct from Materials and Supplies Inventory. (Staff Ex. 7R, p. 7) Company witness M. Getz agreed, under cross-examination by Staff, that hypothetically, if there were a cash working capital component of rate base there would still be a need for the working capital component of rate base that includes materials and supplies inventory. (Tr., pp. 29-30) Cash Working Capital is an expense-based component of Rate Base that allows a utility to earn a return on expenses during the time period between the date the expense is paid and the date the utility is reimbursed for the expense by the ratepayers. (Staff Ex. 7R, p. 7) Materials and Supplies

Inventories are an asset-based component of Rate Base that allows a utility to earn a return on assets after they are purchased and before they are expensed. The Commission found that these two items are separate and distinct components of Rate Base in the Illinois Power Delivery Services Tariff. (Docket Nos. 99-0120/99-0134, Order, pp.23-24 (August 25, 1999))

Furthermore, Staff's adjustment to reduce Materials and Supplies Inventories by the associated accounts payable does not constitute a selective negative working capital item that is only appropriate in the context of a complete working capital analysis. Staff's adjustment does not address cash working capital requirements for utility operating revenues and expenses, but rather the net investment by the Company's shareholders in the Materials and Supplies Inventories. (Staff Ex. 7R, p. 8) Materials and Supplies Inventory is a distinct and separate component of working capital from cash working capital supported by a lead/lag study. The Company's position fails to distinguish the two separate components of Materials and Supplies Inventory—the portion that is still included in inventory and the portion that has been used up and moved to expenses. Staff's adjustment to Materials and Supplies Inventory addresses only the net investment in materials and supplies inventory. Materials and supplies inventory consists of costs that have not yet been included in expenses. It is for this very reason that materials and supplies inventories are included as a component of rate base. Therefore, Staff maintained its direct adjustment to reduce the Company's test year materials and supplies inventory amount by the associated accounts payable. (Staff Ex. 7R, Sch. 7.9) However, Staff revised its adjustment to reflect CILCO's corrected 13-month average inventory balance. (Staff Ex. 7R, p. 8 and Sch. 7.9, line 6)

Staff recommends that the Commission accept Staff's proposed adjustment to reduce materials and supplies inventory for related accounts payable, as reflected in Appendix A, Schedule 1.4, page 1 of 2.

3. Adjustment to Gas Plant, Accumulated Depreciation and Related Depreciation Expense – IDOT Reimbursement

Staff's position is that the Commission should accept the accounting treatment proposed by Staff, which would require the Company to treat the reimbursements from IDOT as Contributions in Aid of Construction ("CIAC") instead of salvage, the treatment currently used by CILCO. Staff further recommends the Commission should direct the Company to record this and future reimbursements for similar projects as Contributions in Aid of Construction, not as salvage, as the Company currently does.

Staff witness Pearce proposed an adjustment to correct the accounting treatment used by the Company to record reimbursements the Company received from IDOT, primarily related to the Route 116 road-widening project (Staff Ex. 7R, pp. 9-13 and Sch. 7.12) The Company indicated that it treats such reimbursements as salvage, recording an increase in accumulated depreciation. (CILCO Ex. 6.9, pp. 3-4)

Staff contends that such reimbursements truly represent CIAC, which are properly recorded as reductions to the balance of plant in service. (Staff Ex. 7R, p. 12) Staff based its conclusion upon Gas Plant Instruction 2(D) of the Uniform System of Accounts for Gas Utilities Operating in Illinois, and proposed an adjustment reflected in

Schedule 7.12 to reflect the proper accounting treatment. Gas Plant Instruction 2(D) states that:

> The gas plant accounts shall not include the cost or other value of gas plant contributed to the company. Contributions in the form of money or its equivalent toward the construction of gas plant shall be credited to the accounts charged with the cost of such construction. Plant constructed from contributions of cash or its equivalent shall be shown as a reduction to gross plant constructed when assembling cost data in work orders for posting to plant ledger of accounts. The accumulated gross costs of plant accumulated in the work order shall be recorded as a debit in the plant ledger of accounts along with the related amount of contributions concurrently being recorded as a credit.

Staff notes that the instruction above makes no distinction between replacement construction and new construction. "Salvage value" is defined in the Uniform System of Accounts for Gas Utilities as:

> the amount received for property retired, less any expenses incurred in connection with the sale or in preparing the property for sale…

Therefore, the reimbursements received, whether for replacement or new construction, do not represent salvage value. Company witness M. Getz, under cross-examination by Staff, agreed that part of the IDOT reimbursement covers the cost of the new installation. (Tr., p. 33) He also explained that the Company not only retired the former gas main, but also installed a new main parallel to the former main that was retired. (Tr., pp. 34-35) Finally, he admitted that the IDOT reimbursement covered much more than the value of the old pipe that was left in the ground by stating that the reimbursement covered replacement cost. (Tr., p. 35) The reimbursements CILCO received from the State of Illinois represent Contributions in Aid of Construction and should properly be credited to gas plant in service, as prescribed in Instruction 2(D), above. Furthermore, Staff's adjustment would reduce the gas plant in service balance to which depreciation rates are applied, resulting in a decrease in test year depreciation expense.

The Company's method of accounting for the reimbursements has no net effect on Rate Base, however, it does not conform to the requirements of Instruction 2(D) and it does result in an overstatement of depreciation expense in the 2001 test year. (Staff Ex. 7R, p. 12) The accounting treatment proposed by the Company would enable CILCO to recover from ratepayers the cost of plant that was not constructed with shareholder funds since the reimbursable projects are included in the balance of gas plant in service that is subject to depreciation. The shareholders should not be entitled to a recovery of the cost of assets funded by contributions.

Staff notes that the Commission found this to be a reasonable adjustment in Docket No. 94-0040, CILCO Gas Rate Case, in which CILCO proposed the same accounting treatment for a transaction similar to the transaction in the current proceeding. (Staff Ex. 7R, p.13) In Docket No. 94-0040 Staff witness Browy proposed an adjustment similar to Staff's adjustment in this proceeding and the Commission accepted Staff's adjustment over the objection of the Company, noting:

> The Commission concludes that Ms. Browy's proposed adjustments should be accepted. The Company's proposed treatment of the State reimbursement for the relocation of the gas main would be appropriate if the reimbursement were considered to be salvage. Based on its review of the record, the Commission determines, however, that the reimbursement is in fact a contribution in aid of construction. Ms. Browy's proposed adjustment reflects the accounting treatment prescribed by the Uniform System of Accounts for contributions in aid of construction. Docket No. 94-0040, Central Illinois Light Company gas rate proceeding, Order, p. 13 (December 12, 1994)

Staff recommends that the Commission accept Staff's proposed adjustment to record the IDOT reimbursements as Contributions in Aid of Construction instead of salvage, as recorded by the Company. Staff further recommends that the Commission instruct the Company to record future reimbursements for similar projects as Contributions in Aid of Construction instead of salvage.

4. Adjustment to Working Capital for Gas in Storage

Staff recommends the Company reduce its requested working capital allowance for gas in storage by $3,459,000. (Staff Ex. 11R, p. 7) The Company disagrees with Staff's recommendation and believes the amount it originally requested is the appropriate value.

Staff's recommendation makes a known and measurable change to the Company's 2001 historical test year, by using 2002 actual data. The Commission's Standard Filing Requirements (83 Illinois Administrative Code Part 285, Section 150 (e)) allow for pro forma adjustments for all known and measurable changes in the operating results of a historical test year. The Company's 2001 test year was a historical test year.

In addition, Staff's basis for using 2002 data, instead of 2001 information, aside from making an allowed known and measurable change was two-fold. First, Staff determined the 2002 calendar year was more representative of how the Company would use leased storage than the 2001 test year. (Staff Ex. 5, p. 5) Second, Staff noted that using 2002 calendar data used the most recent information available that should, in turn, provide the Commission with the best estimate of future cost of gas in storage. (Id.)

Regarding the first point, Staff noted that the Company, during the 2001 test year, maintained gas in storage at two company-owned storage fields and two leased storage fields. However, the contract for one of the leased storage fields ended during 2001, while the other leased storage field's contract began in 2001. In 2002, the Company maintained gas in its two company-owned storage fields and in one leased storage field. Staff considered the 2002 data regarding the value of gas in leased storage to be superior because it provided a continuous view of what the Company did with the inventory at its leased storage field versus the broken view provided by looking at the 2001 data proposed by the Company. (Id.) The Company provided no testimony to dispute Staff's statements on this point.

Regarding the second point, Staff noted that the use of the most recent information available about the Company's gas in storage provided the Commission with the best estimate of future gas costs. (Id.) The Company disputed Staff's arguments on this point.

In particular, the Company stated in its rebuttal testimony, filed on April 17, 2003, that the cost of gas at the present is in line with the cost of gas in 2001 and it expected the price to remain at that level or higher during the next year. (CILCO Ex. 5.2, p. 16) The Company also provided, in CILCO Exhibit 5.4, a comparison of NYMEX gas futures prices for every month from June 1990 through April 2003. Finally, the Company noted, in its surrebuttal testimony, that the NYMEX 2003 prices for the first four months from CILCO Exhibit 5.4 have actually occurred and showed gas cost have increased from the same period from the prior year. (CILCO Ex. 5.7, p. 9) Based on that information, the

Company argues that Staff's adjustment would prevent the Company from recovering its actual costs of providing storage service, by under pricing the cost of gas in storage.

Staff believes it is improper for the Company to use projections of future gas costs as a basis to support keeping its historical 2001 test year values in place. The price of gas that the Company actually pays in the future is unknown. Since the Company selected a historical test year, only known and measurable information is allowed to impact the rates that are set. Therefore, Staff considers the Company's attempt to place reliance on unknown future gas costs as the basis to reject Staff's known and measurable adjustment as improper.

The Company failed to demonstrate that any relationship exists between the value of gas in storage and the NYMEX gas price. When the Company discussed that the gas prices for the first four months of 2003 as known and measurable, Staff noted that those gas cost do not have any relationship to the value to gas in storage. (Tr., p. 489) No relationship exists because for the period January through April 2003, the Company was likely still withdrawing gas rather than injecting gas into storage. (Id.) Therefore, the January through April 2003 cost of gas would not have any bearing on the value of storage gas for that same period.

The record further supports Staff's arguments. Staff Exhibit 5, Schedule 5.1, shows that the value of gas in storage decreased during the period January through April 2002. This indicates that, in 2002, the Company did not start injecting gas into company-owned storage until May. This fact does not support the Company's contention that the gas costs the Company quoted for the first four months of 2003 had any impact of the Company's gas storage costs because it was likely not yet injecting gas into storage. Therefore, there is no known and measurable impact on the value of gas in storage related to the actual gas costs from January through April 2003.

Further, the record demonstrates that the gas costs in the 2001 test year were not representative of historical gas costs. (Staff Ex. 11R, p. 6). In particular, the average gas costs in 2001 were, on average, almost 40¢ higher than the next highest year. (Id.) Whereas the average costs in 2002, even though they contain the third highest average costs are more representative of historical gas costs. (Id., at 6-7) Therefore, the Staff's selection of 2002 is more representative of likely events than the 2001 test year selected by the Company.

The Company chose a 2001 historical test year for its filing. Staff made use of the most recent information available that was consistent with the time period selected by the Company to make an allowed known and measurable change to the amount the Company receives as a working capital allowance for gas in storage. Staff provided two reasons why the known and measurable change is appropriate. The Company could not dispute Staff's first reason and the record supports Staff's second reason. Finally, in order to dispute Staff's recommendations, the Company wants the Commission to consider future and unknown gas cost as the basis for keeping its original request, while rejecting Staff's proposal. Staff does not believe the Company's request is appropriate and that the Commission should recognize the Company's position for what it is -- grasping at straws to avoid a reduction in its allowed base rates.

5. Adjustment to Capitalized Pension and Benefits

Staff witness Hathhorn disallowed $159,000 in rate base to correct the Company's calculation of the 2003 capitalized pensions and benefits amount. (Staff Ex.

8, p. 10, and Schedule 8.7) The amounts for the 2003 capitalized amounts of pensions and OPEB (other post-retirement employment benefits) were calculated using the Towers Perrin actuarial report, discussed below in Section III. B. Adjustment to Pension and Benefits Expense. The Company accepted Staff’s adjustment. (CILCO Ex. 6.9, p. 2) The AG/CUB, however, considers CILCO’s adjustment to rate base for capitalized pension and benefits to be a double-counting. (AB/CUB Ex 1.1, p. 10) At the hearing, though, Mr. Effron admitted in his cross-examination that CILCO actually had pension income, not expense, in 2001, therefore it is not possible to double-count the rate base effect by using the 2003 numbers. (Tr., p. 408) Further, Mr. Effron admitted CILCO’s adjustment is for the incremental increase in capitalized pension and benefits from 2001 to 2003. (Tr., pp. 410-411) Again, this results in no double-counting. Therefore, Staff’s adjustment to correct the Company’s calculation of capitalized pension and benefits is appropriate and should be adopted by the Commission.

III. OPERATING REVENUES AND EXPENSES

A. Uncontested Issues

1. Interest Synchronization

Staff inadvertently reflected the Company's 2001 interest expense (CILCO Sch. C-3.1) before adjustments in the revenue requirement submitted with direct testimony. (Staff Ex. 1, Sch. 1.5) Mr. Effron observed that Staff's interest synchronization needed to be modified to reflect the synchronization adjustment the Company had already reflected in its filing. (AG/CUB Ex. 1.1, p. 13) Staff revised its rebuttal testimony to reflect the correct amount of interest expense as identified by Mr. Effron. (Staff Ex. 7R, Sch. 7.5) in AG/CUB Exhibit 1.1, page 13. CILCO witness Getz agreed that the modified interest synchronization, as reflected on Staff Exhibit 7R, Schedule 7.5 line 4, column (b), should reflect Company interest expense in the amount of $5,719,000. (Tr., p. 25-26) This revision is reflected in Appendix A, Schedule 1.5.

Staff's revision to the interest synchronization adjustment is uncontested (Appendix A, Schedule 1.5) because AG/CUB witness Effron and the Company agree with Staff's revision.

2. Adjustment to Customer Deposits and Related Interest Expense

Staff witness Pearce proposed an adjustment to Customer Deposits to reflect in the Company's test year rate base the 13-month average balance of customer deposits rather than the year-end balance that was reflected by the Company in its filing. (Staff Ex. 1, p. 9, and Sch. 1.10) Schedule 1.10 also presents Staff's proposed adjustment to reflect the Company's test year interest expense on customer deposits. Staff's proposed adjustment increases test year operating expense to reflect interest expense on customer deposits using the current rate of interest approved by the Commission in Docket No. 02-0835. The Company accepted Staff's adjustment (CILCO Ex. 6.2, p. 3) Since the Company reflected the effect of Staff's adjustments in its rebuttal position revenue requirement, ICC Staff Exhibit 7R, Schedule 7.10 reflects no additional adjustment to operating expense.

Staff's adjustment to Interest Expense Related to Customer Deposits is uncontested because the Company adopted the adjustment in its rebuttal position revenue requirement.

3. Adjustment to AM/FM Gas Mapping Pro Forma and Related Amortization Expense

Staff witness Pearce proposed an adjustment to remove from Rate Base a portion of the Company's pro forma adjustment for post-test year plant additions related to the AM/FM Gas Mapping project on the basis that it was not known and measurable. (Staff Ex. 1, p. 7 and Sch. 1.8) Schedule 1.8 also presents the corresponding impact on amortization expense that resulted from the disallowed portion of the AM/FM Gas Mapping Pro Forma adjustment proposed by the Company. However, based on information provided by the Company in rebuttal testimony and analysis of the Company's response to Data Request BAP-065 in support of the 2003 amounts, Staff concluded that the Company's pro forma adjustment for the AM/FM Gas Mapping project was reasonable. Therefore, the amounts of Staff's pro forma adjustment for AM/FM Gas Mapping, shown on ICC Staff Exhibit 7R, Schedule 7.8, match the amounts reflected by the Company in its filing.

Staff's adjustment to the amortization expense related to the AM/FM Gas Mapping project was withdrawn in rebuttal testimony. (Staff Ex. 7R, p. 6)

4. Adjustment to Union Payroll Increase

In direct testimony, Staff witness Hathhorn proposed an adjustment to disallow payroll costs beyond the Company's test year. (Staff Ex. 2, p. 4 and Schedule 2.2) However, in rebuttal testimony, Staff revised the adjustment when CILCO's rebuttal testimony showed her review of Company workpaper WPC-3 was in error. (Staff Ex. 8, p. 4, and Schedule 8.2) Therefore, the Company and Staff are in agreement that no further adjustment to the Company's pro-forma increase to union payroll is necessary.

5. Adjustment to Uncollectibles Expense at Present Rates

In direct testimony, Staff witness Hathhorn calculated an uncollectibles adjustment and a four-year average uncollectibles rate of 0.61% based on the percent of revenues method to adjust the Company's abnormally large 2001 test year balance of uncollectibles expense. (Staff Ex. 2, p. 5 and Schedule 2.4) AG/CUB witness Effron also proposed an uncollectibles adjustment in his direct testimony, based on a five-year average of uncollectibles expense. (AG/CUB Ex, 1.0, Schedule C-2) Staff opposed Mr. Effron's methodology because it did not account for the cost of gas' effect on uncollectibles expense. (Staff Ex. 8, p. 8) In rebuttal, Mr. Effron changed his adjustment to a percent of revenues calculation, using the ratio of actual net write-offs of uncollectible accounts to revenues for the years 1998-2002. (AG/CUB Ex. 1.1, p. 4)

In surrebuttal testimony, the Company stated it accepted Mr. Effron's rebuttal adjustment of $1,812,000. (CILCO Ex. 6.9, p. 9) The Company said Mr. Effron's adjustment was preferable over Staff's because Mr. Effron's adjustment excluded rents and interdepartmental revenues from the calculation. (CILCO Ex. 6.9, p. 9) Since Mr. Effron has changed his methodology to a percent of revenues calculation, which is not materially different from Staff's recommendation (i.e. 0.66% vs. 0.61%), Staff has no opposition to the Company's acceptance of Mr. Effron's adjustment. The Company also agreed that Mr. Effon's average uncollectibles rate of 0.66% should be used in the gross revenues conversion factor calculation in this case. (Tr., pp. 46-47)

6. Supercompressibility and Pressure Factors

Staff recommends that the Company revise its General Terms and Conditions to apply a supercompressibility factor for any gas delivered at pressures over 15 psi.

(Staff Ex. 5, p. 10) Staff also recommended certain revisions to Section 4.140 "Meter Reading – Adjustments" in the Company's terms and conditions that would be consistent with Staff's recommended 15 psi threshold. (Staff Ex. 11R, p. 11) The Company accepted both recommendations. (CILCO Ex. 4.4, p. 2 and CILCO Ex. 4.8. p. 3)

The Company also requested approval to alter the factors it uses for atmospheric and base pressures to make them consistent with AmerenCIPS and AmerenUE. (CILCO Ex. 4.4, p. 2) Staff supports this request. The overall impact of the supercompressibility and pressure factor changes is a reduction in customer usage by 268,164 therms that in turn corresponds to a revenue loss of approximately $26,000. (Id. at 5).

B. Contested Issues

1. Adjustment to YTD September 2002 Gas Plant Additions and Related Depreciation Expense

Staff's position is that AG/CUB witness Effron's proposed adjustment to disallow all post-2001 pro-forma plant additions and the related depreciation expense (AG/CUB Ex. 1.0, Sch. B) should be accepted by the Commission. Staff bases this conclusion on the fact that the net plant in service balance at the end of 2002 is lower than the net plant in service balance at the end of 2001, the historic test year selected by the Company. The rationale for Staff's position is further explained in Section II, B. 1.

Staff witness Pearce proposed an adjustment to remove from Rate Base certain post-test year plant additions that were inadvertently duplicated by the Company in its filing as part of the pro forma adjustment for YTD September 2002 gas plant additions and as CWIP. (Staff Ex. 1, Sch. 1.7) Schedule 1.7 also presents the impact on rate base and operating expenses that resulted from the elimination of the duplicate additions. The Company accepted Staff's proposed adjustment. (CILCO Ex. 6.2, pp.4-5) Since the Company reflected the effect of Staff's adjustments in its rebuttal position revenue requirement, Staff Exhibit 7R, Schedule 7.7 reflects no further adjustment to operating expense.

However, CUB/AG witness Effron opposed the Company's pro forma adjustment to increase rate base for post-test year additions of $14,139,000 (CILCO Section 285.2015, Sch. B-2.1) less $821,000 of related accumulated depreciation (CILCO Section 285.2050, Sch. B-3.1), in its entirety because the Company's net plant in service balance at December 31, 2002 was lower than the net plant in service balance at December 31, 2001. (AG/CUB Ex. 1.0, pp. 5–9 and Sch. B)

Staff recommends that the Commission accept AG/CUB witness Effron's proposed adjustment to disallow depreciation expense related to all post-test year pro forma plant additions. Staff has calculated the additional impact of adopting AG/CUB witness Effron's adjustment on Appendix A, Schedule 1.7.

2. Adjustment to Gas Plant, Accumulated Depreciation and Related Depreciation Expense – IDOT Reimbursement

Staff witness Pearce proposed an adjustment to correct the accounting treatment used by the Company to record reimbursements the Company received from the Illinois Department of Transportation ("IDOT"), primarily related to the Route 116 road-widening project (Staff Ex. 7R, Sch. 7.12) The Company indicated that it treats such reimbursements as salvage, recording an increase in accumulated depreciation.

Staff contends that such reimbursements truly represent CIAC, which are properly recorded as reductions to the balance of plant in service. Staff's adjustment would reduce the gas plant in service balance to which depreciation rates are applied, resulting in a decrease in test year depreciation expense. The Company's method of accounting for the reimbursements has no net effect on Rate Base, however, it does not conform to the requirements of Instruction 2(D) and it does result in an overstatement of depreciation expense in the 2001 test year.

Staff recommends that the Commission accept Staff's proposed adjustment to record the IDOT reimbursements as Contributions in Aid of Construction instead of salvage, as recorded by the Company. Staff further recommends that the Commission instruct the Company to record future reimbursements for similar projects as Contributions in Aid of Construction instead of salvage.

3. Income Tax Expense – Cushion Adjustments

Staff's position is that the Commission should accept AG/CUB witness Effron's proposed adjustment to remove from the calculation of 2001 income tax expense certain cushion adjustments.

AG/CUB witness Effron proposed in his direct testimony to eliminate from the calculation of state and federal income tax expense the effect of $13,000 and $142,000, respectively, of cushion adjustments on state and federal income tax expense and the effect on federal income taxes of the true-up to the provision for state income taxes. (AG/CUB Ex. 1.0, p. 27) Mr. Effron describes both items as being of an "unusual and nonrecurring nature". AG/CUB witness Effron further addressed this adjustment in rebuttal testimony. (AG/CUB Ex. 1.1, p. 12)

The Company disagreed with Mr. Effron's proposed adjustment stating that Mr. Effron's proposal would preclude the Company from recovering any expense unless the identical expense recurs each and every year. (CILCO Ex. 6.2, p. 29) In surrebuttal testimony, Company witness Getz agreed that the deferred taxes to which Mr. Effron refers should appropriately be excluded from the revenue requirement calculation, however, he explained that the Company believes the adjustment should be ($13,000) for state and ($74,000) for federal taxes versus the ($13,000) for state and ($142,000) for federal taxes that are reflected on AG/CUB Exhibit 1.0, Schedule C-5, included with Mr. Effron's direct testimony. (CILCO Ex. 6.9, p. 11) The Company believes Mr. Effron erroneously included $68,000 of federal income taxes related to the 2001 true-up provision in his adjustment. According to CILCO, the actual cushion adjustments were $13,000 for state and $74,000 for federal income taxes, which total to an $87,000 adjustment. (Id.)

Staff agrees with AG/CUB witness Effron that the effects of both the state provision true-up and cushion adjustment should be eliminated from the calculation of federal income tax. Therefore, this adjustment has been reflected in the revenue requirement attached to this Brief. (Appendix A, Sch. 1.2, page 2 of 2)

Staff recommends that the Commission accept the adjustment proposed by AG/CUB witness Effron related to the impact of state provision true-up and cushion adjustments on the calculation of federal and state income taxes.

4. Adjustment to Rate Case Expense

Staff witness Hathhorn disallowed $135,000 in operating expenses to amortize the Company's rate case expense over a 5-year period, rather than 3 years, as proposed by the Company (Staff Ex. 8, Schedule 8.1[2]). The Company's position for a 3-year period is unsupportable. CILCO witness Getz presents the history of gas rate filings, in his surrebuttal testimony at page 10. Prior to the instant case, the last CILCO gas rate cases were filed in 1990 and 1994. CILCO's alleged 3-year average rate case history makes use of the period 1974 through 1981, when six rate cases were filed over seven years. (CILCO Ex. 6.9, p. 10) The Commission has previously considered this period of time in determining the proper rate case amortization period, in CILCO's last gas rate case, Docket No. 94-0040. In that case, the Commission ruled in favor of Staff's adjustment for a 5-year amortization period, over the objections of the Company, which had argued for a 3-year period (Docket No. 94-0040, Order Dated Dec. 12, 1994, at p. 69). The facts show that the instant case is only the fourth gas rate case filed by CILCO since 1981. (CILCO Ex. 6.9, p. 10 and Tr., p.65)

CILCO further argues that a 3-year amortization period is also appropriate since Ameren now owns CILCO. (CILCO Ex. 6.2, p. 25) However, the Ameren subsidiaries only have a five-year average rate case history, not three. The most recent gas rate case for Central Illinois Public Service Company ("CIPS") and Union Electric Company ("UE") was in 1998, Docket No. 98-0546. Prior to that, CIPS conducted rate cases in 1991, 1990, and 1982, while UE's prior rate case dates back to 1984. (Staff Ex. 8, pp. 2-3)

Finally, CILCO states that Ameren agreed to a stay-out provision for the gas business until 2005, and anticipates that a gas case will be filed shortly after that

[2] Schedule 8.1 is Staff's rebuttal schedule. It is identical to Staff Exhibit 2, Schedule 2.1, Staff's Direct testimony schedule.

provision expires (CILCO Ex. 6.2, pp. 25-26). However, while CILCO is precluded from filing a gas rate case prior to 2005, this is no guarantee that the Company definitely will file in 2005.

Since none of the rate case histories for CILCO, CIPS, nor UE supports a three-year amortization period, and the stay-out provision is not a guarantee of future rate case activity, the Commission should adopt Staff's adjustment to amortize rate case expense over five years.

The Company also requested that, if the Commission determines a five-year amortization of rate case expense is appropriate, that the final order in this proceeding specifically state that the Company shall be allowed to include in future rate cases any unamortized balance related to rate case expense. (CILCO Ex. 6.2, p. 26) Staff notes that it is the Commission's current practice is to allow a utility to include unamortized rate case expense in rate base. However, Staff cannot commit a future Commission to this same practice. (Staff Ex. 8, p. 3)

Finally, Staff notes that its adjustment is identical to that of Mr. Effron's adjustment in AG/CUB Exhibit 1.0, Schedule C-2.

5. Adjustment for Non-Recurring Expense

Staff witness Hathhorn disallowed $31,000 in operating expenses for the cost of a contract employee because the cost is a non-recurring expense. (Staff Ex. 2, p. 4 and Schedule 8.3[3]) The contractor filled a shift until a new employee could be trained, and is not an on-going expense of the Company. (Staff Ex. 2, p. 5) The Company does not

[3] Schedule 8.3 is Staff's rebuttal schedule. It is identical to Staff Exhibit 2, Schedule 2.3, Staff's Direct testimony schedule.

dispute that the cost is a one-time occurrence. (CILCO Ex. 6.2, pp. 15-17) CILCO argues that it always has some level of non-recurring expense; therefore no adjustment should be made. (CILCO Ex. 6.2, p. 16)

Staff argues that the test period should reflect a normal, recurring level of expenditures. (Staff Ex. 8, p. 5) Items that are of a one-time nature are usually excluded from the revenue requirement, or, in certain circumstances, are allowed to be amortized over an appropriate recovery period. CILCO has not established why this immaterial amount of non-recurring contractor expense should be allowed in the revenue requirement, and treated as the exception to this general rule in ratemaking. Nor has CILCO requested or established that its contractor expense warrants amortization. Therefore, Staff's adjustment to remove a one-time expense from the revenue requirement should be adopted by the Commission, consistent with this Commission's usual ratemaking practices.

6. Adjustment to Incentive Compensation Expense

Staff witness Hathhorn disallowed $112,000 in operating expense for the cost and related payroll taxes of the Company's Sales, Marketing, and Trading Unit incentive compensation Plan ("SMT Plan"), because the goals of the SMT Plan are financial in nature, which primarily benefit shareholders, and create a circular effect when the expense is allowed to be included in the revenue requirement. (Staff Ex. 2, pp. 6-7) AG/CUB witness Effron also proposed an adjustment for incentive compensation expense, however it disallowed both the SMT Plan and the Company's Energy Delivery Unit Plan ("EDU Plan"). (AG/CUB Ex. 1.0, Schedule C-2) The Company accepted Staff's adjustment in its rebuttal testimony. (CILCO Ex. 6.2, p. 20)

Mr. Effron presented no analysis of the Company's plans. His sole reason for his adjustment is the prior Order in CILCO Docket No. 94-0040, which disallowed the Company's incentive compensation expense at that time. (AG/CUB Ex. 1.0, p. 23) Staff's analysis of Company documentation on the EDU Plan is that the EDU Plan is consistent with the Commission's practice of allowing rate recovery for incentive compensation plans that provide ratepayer benefits. (Staff Ex. 8, pp. 8-9) CILCO presented a description of the EDU Plan in its rebuttal testimony. (CILCO Ex. 6.2, pp. 18-19)

AG/CUB never rebutted the merits of the EDU Plan or Staff's analysis of such plan. Rather, at the hearing, AG/CUB questioned both Company witness Getz and Staff witness Hathhorn as to the continuation of CILCO's plans while owned by Ameren. (Tr., pp. 58-60 and pp. 396-397, respectively) AG/CUB presented AG Cross Exhibit #3, which is a data request response by CILCO that states a comparable but separate plan may be implemented for AmerenCILCO employees in the future, but the timing is unknown and unmeasurable. Staff witness Hathhorn explained in her cross-examination that this data request response is insufficient evidence to support a known and measurable adjustment to an historical test year. (Tr., p.397) She explained that she analyzed the plans in place during the 2001 test year, and the response does not sufficiently explain how the plans will change in the future and what effect those changes will have on the level of incentive compensation expense. Therefore, there is insufficient evidence to remove the Company's incentive compensation expense based upon a known and measurable change. Staff's adjustment to remove the cost of the

SMT Plan and allow the cost of the EDU Plan is reasonable and should be adopted by the Commission.

7. Adjustment to Pension and Benefits Expense

Staff disallowed $493,000 in operating expense to update the Company's estimate of its 2003 costs, presented in CILCO Rebuttal Exhibit 6.5, page 1 of 2, to the actual expense amounts per the final CILCO actuarial report. (Staff Ex. 8, p. 9 and Schedule 8.6) Staff used the Company's calculation of the proper amount of operations and maintenance expense in its calculation. This percentage was disputed by AG/CUB witness Effron in direct testimony, but accepted in his rebuttal. (AG/CUB Ex. 1.1, p. 10) The Company accepted Staff's adjustment in its surrebuttal testimony (CILCO Ex. 6.9, p. 2), however, AG/CUB opposes the Company's pension and benefits expense because it was prepared using assumptions for Ameren's benefit plans, rather than CILCO's. (AG/CUB Ex. 1.1, pp. 7-10)

AG/CUB considers the increase in expense using the Ameren assumptions, in the Towers Perrin actuarial report, over the CILCO assumptions, in the Buck Consulting actuarial report, a cost of the acquisition of CILCO by Ameren, and therefore, barred to be passed on to ratepayers, as agreed to as a condition of approval in Docket No. 02-0428. (AG/CUB Ex. 1.1, p. 7 and p. 9) CILCO presented surrebuttal witness Vogl to further explain the differences in the two actuarial reports and assumptions therein. (CILCO Ex. 10.0) The Towers Perrin report reflects the assumptions that will be used by CILCO on a going-forward basis. As such, it is the appropriate documentation for a known and measurable change to a historic test year expense. The Order in Docket No. 02-0428 does not bar CILCO from such an adjustment. The AG/CUB has failed to establish that the increased pension and benefits expense are properly categorized as acquisition costs of CILCO by Ameren. Therefore, Staff's adjustment, in Schedule 8.6, is a proper adjustment to update an estimate to an actual amount of expense as a known and measurable change, and should be adopted by the Commission.

IV. COST OF CAPITAL/RATE OF RETURN

CILCO and Staff did not agree on the cost of common equity for CILCO Gas and whether CILCO Gas' cost of common equity should include a flotation cost adjustment.

A. Capital Structure - Uncontested

For setting CILCO Gas' rates in this proceeding, Staff recommended a June 30, 2002, capital structure comprising 45.69% long-term debt (i.e., \$314,706,894), 5.77% preferred stock (i.e., \$39,735,976) and 48.54% common equity (i.e., \$334,284,000). (Staff Ex. 3.0, Sch. 3.1)

CILCO's current S&P credit rating is A- and its business profile score is 4. Those ratings reflect CILCO's current affiliation with CILCORP and Ameren. (Staff Ex. 3.0. p. 7) Section 9-230 of the Public Utilities Act ("Act") prohibits the Commission from including any incremental risk or increased cost of capital that is the direct result of the public utility's affiliation with unregulated or non-utility companies. Therefore, CILCO's risk level and cost of capital should be measured without regard to the effect of the Company's affiliation with CILCORP and Ameren. (Id., at 8) Ms. Phipps used a credit rating benchmark of AA- because her ratio analysis of CILCO's financial strength indicates CILCO would have maintained its former AA- credit rating if not for its affiliation with CILCORP and Ameren. Thus, Ms. Phipps compared CILCO's June 30, 2002, capital structure to Standard & Poor's ("S&P") benchmarks for AA-rated utilities with business profile scores of 4. (Staff Ex. 3.0, pp. 8-10) According to S&P, the total debt to total capital ratio for AA-rated utilities with business profile scores of 4 is between 37.5% and 43.0%. Ms. Phipps testified that CILCO's June 30, 2002, total debt ratio of 45.7% is very close to the S&P benchmark. (Staff Ex. 3.0, pp. 6-7) Staff's proposed capital structure and resulting cost of capital recommendation for CILCO Gas are presented on Appendix B.

For the purpose of this proceeding, the Company accepted Staff's proposed capital structure. (CILCO Ex. 8.3, p. 2)

B. Cost Of Long-Term Debt - Uncontested

Ms. Phipps' proposed 5.98% cost of long-term debt reflects the current cost of CILCO's three outstanding variable interest rate bank loans. To properly reflect the June 30, 2002, cost of long-term debt, Ms. Phipps reduced the unamortized debt expense balance for all existing debt obligations to reflect an additional six months of amortization and calculated the annual amortization of debt expense, discount and premiums for all debt obligations using straight-line amortization. (Staff Ex. 3.0, pp. 10-11) For the purpose of this proceeding, the Company accepted Staff's proposed cost of long-term debt. (CILCO Ex. 8.3, p. 2)

C. Cost Of Preferred Stock - Uncontested

Ms. Phipps and Mr. O'Bryan agree that the Company's embedded cost of preferred stock is 5.43%. (CILCO Ex. 8.0 Rev., p. 4; Staff Ex. 3.0, p. 11)

D. Cost Of Common Equity - Contested

Dr. Lesser recommended an 11.73% cost of equity for CILCO Gas, which includes a seven basis points flotation cost adjustment. (CILCO Ex. 7.10 Rev., p. 34)

Ms. Phipps recommended a 10.47% cost of equity for CILCO Gas, which does not reflect a flotation cost adjustment. (Staff Ex. 9.0, pp. 1 and 5)

1. CILCO Witness Lesser's Analysis

Dr. Lesser estimated CILCO Gas' cost of common equity using the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM") and a Risk Premium Model ("RPM"). Dr. Lesser applied those models to a sample of gas distribution companies ("Gas Sample"). (CILCO Ex. 7.10 Rev., p. 31)

a. DCF Analysis.

Dr. Lesser applied his DCF analysis to the companies composing his Gas Sample using February 28, 2003, growth rate estimates from Institutional Brokers Estimate System ("IBES") and Zack's Investment Research ("Zacks"). He estimated prospective dividend yields for the companies composing his Gas Sample by applying each company's growth rate estimate to a dividend yield that is based on a 30-day average stock price. Dr. Lesser added the growth rate and dividend yield estimates to calculate individual cost of equity estimates for the companies composing his Gas Sample. The average of those individual company estimates equals 10.77%. (CILCO Ex. 7.10 Rev., pp. 31-32)

b. CAPM Analysis.

Dr. Lesser developed two cost of equity estimates with the CAPM, using two different risk-free rate of return estimates. His 5.33% risk-free rate estimate is an average of the forecasted yield on long-term U.S. Treasury bonds for the six quarters ending the third quarter of 2004, as published in the April 2003 issue of Blue Chip Financial Forecasts. His 6.0% risk-free rate estimate is based on the economic forecasts provided in Ms. Phipps' direct testimony, which he erroneously identified as Ms. Phipps' estimate of the risk-free rate. He estimated that beta, which is the measure of risk in the CAPM, equals 0.70. Dr. Lesser's estimate of beta equals the average Value Line beta estimates for the individual companies composing his Gas Sample. Dr. Lesser used Ms. Phipps' original estimate of the market rate of return of 14.29% in combination with each of his risk-free rate estimates to estimate the market risk premium. (In rebuttal testimony, Ms. Phipps updated her cost of equity analysis, including her estimate of the market rate of return. Thus, Ms. Phipps' CAPM analysis reflects a 14.37% market rate of return. See Staff Ex. 9.0, pp. 4-5) Inputting those values into the CAPM produced cost of common equity estimates of 11.60% (using a 5.33% risk-free rate) and 11.80% (using a 6.00% risk-free rate) for the Gas Sample. (CILCO Ex. 7.10 Rev., p. 32)

c. RPM Analysis.

For his RPM analysis, Dr. Lesser subtracted a six-quarter forecasted 6.42% yield on Aaa-rated corporate bonds from Ms. Phipps' 14.29% market rate of return estimate to estimate a market risk premium. Dr. Lesser multiplied the market risk premium by his Gas Sample beta estimate and added that beta-adjusted market risk premium estimate to an extrapolated A-rated bond yield of 6.99%. Dr. Lesser's RPM estimated the cost of common equity for the Gas Sample equals 12.50%. (CILCO Ex. 7.10 Rev., p. 33)

d. Recommendation.

Dr. Lesser concluded CILCO Gas' cost of common equity ranges from 11.62% to 11.69%. Dr. Lesser added seven basis points to his cost of equity estimates for flotation costs incurred by CILCO. Dr. Lesser recommended an 11.73% cost of equity for CILCO

Gas, which represents the average of his DCF-, CAPM- and RPM-derived cost of equity estimates. (CILCO Ex. 7.10 Rev., p. 34)

2. Staff Witness Phipps' Analysis

Staff Witness Phipps estimated CILCO Gas' cost of common equity with DCF and risk premium models. DCF and risk premium models cannot be applied directly to CILCO because its common stock is not market-traded. Therefore, Ms. Phipps applied those models to a sample of natural gas distribution companies comparable in risk to CILCO Gas ("LDC Sample"). The LDC Sample comprises nine cash dividend paying, market-traded domestic natural gas distribution utilities within the *Standard & Poor's Utility Compustat* database that had S&P credit ratings of A- and better; were not involved in any pending merger; and for which Value Line beta estimates and either IBES or Zacks growth forecasts were available. (Staff Ex. 3.0, pp. 12-13) Ms. Phipps LDC Sample is identical to Dr. Lesser's Gas Sample, excepting Ms. Phipps' LDC Sample includes New Jersey Resources whereas Dr. Lesser's Gas Sample does not.

a. DCF Analysis.

DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments. Since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that stock prices embody. The LDC Sample companies pay dividends quarterly. Therefore, Ms. Phipps applied a constant-growth quarterly DCF model. (Staff Ex. 3.0, p. 14)

DCF methodology requires a growth rate that reflects the expectations of investors. (Staff Ex. 3.0, p. 15) Ms. Phipps measured the market-consensus expected growth rates with projections published by IBES and Zacks. The growth rate estimates were combined with the closing stock prices and dividend data as of May 13, 2003. (Staff Ex. 9.0, p. 3) Based on this growth, stock price, and dividend data, Ms. Phipps' DCF model estimated the cost of common equity for the LDC Sample is 10.28%. (Staff Ex. 9.0, p. 3)

b. Risk Premium Analysis.

According to financial theory, the required rate of return for a given security equals the risk-free rate of return plus a risk premium associated with that security. The risk premium methodology is consistent with the theory that investors are risk-averse. That is, investors require higher returns to accept greater exposure to risk. In equilibrium, two securities with equal quantities of risk have equal required rates of return. Ms. Phipps used a one-factor risk premium model, the CAPM, to estimate the cost of common equity. In the CAPM, the risk factor is market risk, which cannot be eliminated through portfolio diversification. (Staff Ex. 3.0, pp. 18-19)

The CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market. (Staff Ex. 3.0, p. 15) Ms. Phipps used two estimates of beta: Value Line's adjusted beta estimates and those calculated through a regression analysis. The average Value Line beta estimate for the LDC Sample was 0.69 and the regression beta estimate for the LDC Sample was 0.52. Ms. Phipps considered two current estimates of the risk-free rate of return: the 1.09% yield on three-month U.S. Treasury bills and the 4.85% yield on long-term U.S. Treasury bonds. Both estimates were measured as of May 13, 2003. Forecasts of long-term inflation and the real risk-free rate imply a long-term, nominal risk-free rate between 5.7% and 6.3%, which suggests that the U.S. Treasury bond yield is currently the superior proxy for the long-term risk-free rate. Finally, to measure the expected rate of return on the market, Ms. Phipps conducted a DCF analysis on the firms composing the S&P 500 Index. That analysis estimated that the expected rate of return on the market equals 14.37%. Inputting those three parameters into her risk premium model, Ms. Phipps estimated the cost of common equity for the LDC Sample equals 10.66%. (Staff Ex. 9.0, pp. 4-5)

c. Recommendation.

Ms. Phipps testified that a thorough cost of common equity analysis requires both the application of financial models and the analyst's informed judgment. (Staff Ex. 3.0, p. 28) Along with DCF and risk premium analyses, Ms. Phipps considered the observable 6.19% rate of return that the market currently requires on less risky A-rated long-term debt. Based on Ms. Phipps analysis, the investor-required rate of return on common equity for CILCO Gas equals 10.47%, which represents the average of her DCF and CAPM estimates for the LDC Sample. (Staff Ex. 9.0, p. 6)

3. Contested Issues Regarding the Rate of Return on Equity

a. Sample Selection.

Although Dr. Lesser ultimately conceded that Ms. Phipps' LDC Sample was reasonable for estimating CILCO Gas' cost of common equity, his criticisms of her LDC Sample illuminates the issue of his creditability as an expert[4] on utilities' cost of common equity. (CILCO Ex. 7.17 Rev., pp. 12-16)

First, Dr. Lesser mischaracterized Ms. Phipps' testimony relating to New Jersey

[4] Dr. Lesser completed three finance courses in 1982 and 1983. Twenty years later, Dr. Lesser testified on the cost of capital issue for the first time in a proceeding before the Arkansas Public Service Commission. Dr. Lesser's testimony in the instant proceeding is the second cost of equity analysis presented by Dr. Lesser in a regulatory rate proceeding. (Tr., pp. 305-306)

Resources ("NJR"). He wrongly alleged that Ms. Phipps challenged his revenue-based exclusion of NJR. (CILCO Ex. 7.17 Rev., pp. 13-14) To the contrary, Ms. Phipps never criticized Dr. Lesser's Gas Sample for omitting NJR.

Second, Dr. Lesser implied that Ms. Phipps focused on operating and net income as screening criteria for selecting companies for her LDC Sample. (CILCO Ex. 7.17 Rev., p. 14) While Ms. Phipps did examine the sources of NJR's earnings and the types of its investment to determine whether NJR's principal business was regulated natural gas distribution, they were not part of her screening criteria. Rather, in selecting the LDC Sample companies, Ms. Phipps focused on whether each company was comparable in risk to CILCO Gas and whether the she had the data required for her analysis. (Staff Ex. 3.0, pp. 12-13; Staff Ex. 9.0, pp. 2-3)

Third, Dr. Lesser attempted to discredit Ms. Phipps' DCF analysis when he stated, "Ms. Phipps also did not include in her comparability criteria a requirement that companies not have reduced or eliminated dividends in the past few years. Such constancy of dividend payments is fundamental to using the DCF model." (CILCO Ex. 7.17 Rev., p. 14, Footnote 12) Yet, Dr. Lesser admitted that none of the companies composing Ms. Phipps' LDC Sample have reduced or eliminated dividends since <u>at least</u> 1998. (Tr., at 309) Thus, Dr. Lesser's claims are baseless.

Fourth, in his surrebuttal testimony, Dr. Lesser conceded the NJR issue but his explanation for that concession strongly suggests that his initial criticism of its inclusion in Ms. Phipps' LDC Sample was contrived. Dr. Lesser argued that on an *ex post* basis, inclusion of NJR in Ms. Phipps' LDC Sample is not *per se* unreasonable given the 16 basis point difference between Ms. Phipps 10.44% cost of equity estimate for NJR in comparison to her 10.28% cost of equity estimate for her LDC Sample. (CILCO Ex. 7.17 Rev., pp. 15-16) In other words, Dr. Lesser concluded that the small difference in the costs of equity of NJR and Ms. Phipps' LDC Sample indicates that NJR can be included in an LDC Sample. In contrast, when Ms. Phipps' direct testimony-phase DCF analysis estimated a 15 basis point difference between the 10.55% cost of equity for NJR and a 10.70% cost of equity for her LDC Sample (Staff Ex. 3.0, Sch. 3.8), Dr. Lesser argued that inclusion of NJR in Ms. Phipps' LDC Sample was unreasonable. (CILCO Ex. 7.10 Rev., p. 3) Dr. Lesser also excluded NJR from his updated DCF analysis, which resulted in a higher cost of equity estimate for his Gas Sample than would result if he had included NJR. (CILCO Ex. 7.10 Rev., pp. 31-32 and Footnote 14) The evidence suggests that Dr. Lesser's original opposition to the inclusion of NJR in Ms. Phipps' LDC Sample had less to do with whether NJR was primarily a natural gas distribution utility than because NJR's DCF-derived cost of equity estimate was lower than that for the LDC Sample.

In summary, Dr. Lesser's criticisms of Ms. Phipps' LDC Sample rested on a foundation of mischaracterizations and contrivances. His performance on this issue did nothing to enhance his credibility as a cost of equity expert.

b. DCF Analysis

i. Efficient Market Hypothesis

The Efficient Market Hypothesis ("EMH") posits that stock prices immediately reflect all available information. (Staff Ex. 9.0, p. 14) According to Dr. Lesser, reliance on a single day's closing stock price to estimate CILCO Gas' cost of common equity using the DCF model raises the question of the nature and reliability of the EMH. Dr.

Lesser asserts that the nature of the EMH and the controversies surrounding it were clarified in two articles. (CILCO Ex. 7.10 Rev., pp. 5-8) Ms. Phipps testified that those articles do not support Dr. Lesser's 30-day average stock prices. In fact, those two articles and another article that Ms. Phipps cited indicate that pricing irregularities do not invalidate the implications of the EMH. (Staff Ex. 9.0, pp. 14-16)

Dr. Lesser argued that Ms. Phipps' "mechanical interpretation of the EMH implies that the price of a stock on a given day completely reflects investor expectations regarding the present value of that stock, regardless of whether, even as Ms. Phipps also admits, investors make mistakes in valuing stocks." (CILCO Ex. 7.17 Rev., p. 7) Dr. Lesser alleges that Ms. Phipps' testimony implies any calculation of the cost of equity using a given day's closing stock price may be the "correct" price with which to calculate a cost of equity value. (CILCO Ex. 7.10 Rev., p. 10) In her uncontradicted response, Ms. Phipps testified that while investors may make mistakes in valuing common stocks, the market is efficient in the sense that it quickly and accurately reflects investor expectations. Although investor expectations may differ from actual returns, the investor-required rate of return, which is based on expectations, is the appropriate measure for estimating the cost of equity for a utility since investor expectations, not investors' ability to correctly value securities, determine the price investors will pay to buy a common stock. (Staff Ex. 9.0, pp. 23-24)

Ms. Phipps' rebuttal testimony described the problems inherent in Dr. Lesser's use of historical stock prices in the DCF model. Specifically, she testified that (1) only current stock prices reflect all information that is available and relevant to the market whereas using historical data gives undue weight to information that may be obsolete;

(2) reliance on historical average stock prices implies that stock prices will revert to some mean, which is questionable given security returns approximate a random walk, suggesting no tendency of mean reversion; (3) even if securities prices were mean reverting, which they are not, no method exists for determining the true value of that mean; (4) since no proven method exists for determining the appropriate measurement period to use, any measurement period chosen is arbitrary; and (5) using historical data to estimate market-required rates of return render such estimates susceptible to manipulation. (Staff Ex. 9.0, pp. 16-17)

Although Dr. Lesser advocated using historical average stock prices in the DCF model and asserted that historical average stock prices are useful in estimating the cost of equity, he never provided the basis for that assumption. (CILCO Ex. 7.17 Rev., p. 8) Staff asserts that using historical stock price data to estimate CILCO Gas' cost of equity effectively substitutes actual measurement error for potential measurement error. That is, averages of historical stock prices <u>increases</u> measurement error since they reflect information that the market may no longer consider relevant whereas single day stock prices <u>may</u> subject a cost of equity estimate to measurement error since investors may reassess stock values. However, using a sample of companies to estimate the cost of equity reduces the amount of measurement error associated with single stock prices of individual companies. Furthermore, using an average historical stock price obscures the market's continual reassessment of a stock's value, as illustrated by Ms. Phipps' discussion of Nicor stock prices. (Staff Ex. 9.0, pp. 19-21)

In response, Dr. Lesser provided hypothetical examples that suggest if Ms. Phipps had chosen a stock price measurement date in which Nicor's stock price rose or fell substantially then her cost of equity recommendation would be unreasonable. (CILCO Ex. 7.17 Rev., pp. 9-10) Staff asserts those hypothetical examples are irrelevant since Nicor's stock price neither rose nor fell substantially on Ms. Phipps' stock price measurement date. Moreover, Ms. Phipps took steps to ensure that her DCF estimates of the investor-required rate of return on common equity were reasonable. (Tr., at 349) Those procedures would have prevented unusual cost of equity estimates for Nicor from unduly affecting her recommended rate of return. Finally, Dr. Lesser never explained how a 30-day average of historical stock prices would increase "reasonableness." To the contrary, a 30-day average of historical stock prices can create more problems than it solves. For example, on March 11, 2003, investors decided that regulatory actions against Nicor would be less severe than first believed. Thus, a cost of equity estimated using Nicor's March 11, 2003, stock price would differ from that using Nicor's March 10, 2003, stock price. However, a 30-day average stock price ending March 11, 2003, would have included the stock price from March 10, 2003, when investors' expectations caused Nicor's stock price to fall substantially, and stock prices prior to March 10, 2003, when investors were unaware of any potential regulatory actions whatsoever.

Dr. Lesser asserted that his use of a 30-day average stock price in the DCF model "represents a <u>reasonable</u> compromise between the absolute tenets of the EMH and the desire to develop a more stable [cost of equity] estimate." (CILCO Ex. 7.17 Rev., p. 12) Yet, Dr. Lesser never defined the degree of stability that is desirable let alone that a 30-day historical average stock price is necessary or even sufficient to achieve it. Dr. Lesser testified that Federal Energy Regulatory Commission ("FERC") and the public utility regulatory agencies in Connecticut, Oklahoma and California use six-month average stock prices and dividend payments in the DCF model. (CILCO Ex. 7.17 Rev., p. 11) Neither the FERC nor those regulatory agencies referred to by Dr. Lesser use the same 30-day average stock price that he used to estimate CILCO Gas' cost of equity. Clearly, the FERC and three state jurisdictions believe that 30 days is insufficient to achieve the degree of "stability" they desire. In surrebuttal, Dr. Lesser opined that FERC's use of a six-month average stock price is reasonable. (CILCO Ex. 7.17 Rev., pp. 10-12) This is a reversal from the position taken in his direct testimony where he described the FERC DCF model as having an intuitive appeal, but quite arbitrary and subject to criticism. (CILCO Ex. 7.0 Rev., p. 31) Staff submits that Dr. Lesser's 30-day historical average is an arbitrary period, which he has not shown to increase cost of equity estimation stability in comparison to single day stock prices.[5]

Dr. Lesser also asserted that Ms. Phipps' argument that stock prices change with the approach of a dividend payment date is unfounded and contradicts the EMH. (CILCO Ex. 7.10 Rev., p. 11) This assertion betrays a misunderstanding of present value theory. If stock prices did not change as dividend payment dates approach, then the very foundation of the DCF model, the time value of money, would be invalid and there would be no "ex-dividend effect," which is the tendency of stock prices to decline on the ex-dividend date. Furthermore, the approach of a dividend payment date is known to all investors; and thus, reflected in stock prices. Therefore, it does not violate the EMH. Finally, growing dividend payments are part of the uptrend in common stock

[5] CILCO Ex. 7.11 purports to show volatility in DCF-derived cost of equity estimates that use daily stock prices. However, as Ms. Phipps testified, CILCO Ex. 7.11 incorrectly uses the same IBES and Zacks growth rates for the entire three-month period and miscalculates the expected dividend. (Staff Ex. 9.0, pp. 19 and 24-25) Thus, the cost of equity estimates shown in CILCO Ex. 7.11 are invalid.

prices that are the sole exception to the random walk theory. Stock price trends rise between ex-dividend dates, decline on the ex-dividend date and continue this cycle in an upward trend that reflects growth. However, recognizing the existence of an underlying trend in stock prices is not mutually exclusive from recognizing that stock prices are volatile; that is, variability can exist around that trend. (Staff Ex. 9.0, pp. 22-23)

ii. Dividend Payment Assumptions

Dr. Lesser alleged that Ms. Phipps' DCF analysis did not use the correct future dividend payments as specified in the DCF model presented in her testimony since Ms. Phipps made the realistic assumption that dividends increase once per year, during the same quarter as the previous year's change. (CILCO Ex. 7.10 Rev., pp. 11-12) Dr. Lesser agreed that the companies composing Ms. Phipps' LDC Sample probably do not adjust their dividends more frequently than once per year. Remarkably, he found this to be immaterial to the calculations made using the DCF model. Dr. Lesser mechanistically followed the DCF model presented in Staff Exhibit 3.0, page 15, and increased each company's most recent dividend payment by the earnings growth rate without regard to whether a company had already increased its dividend. Dr. Lesser's approach resulted in expected dividend payments for three companies[6] that increased twice during one year. (Staff Ex. 3.0, Sch. 3.6; CILCO Ex. 7.13) This unrealistic assumption upwardly biased Dr. Lesser's DCF-derived cost of equity analysis. (Staff Ex. 9.0. p. 24) Thus, it should be rejected.

The expected dividend issue presented another example of Dr. Lesser's

[6] Those companies are Atmos Energy Corporation, New Jersey Resources and WGL Holdings.

inconsistency. When asked whether he believed that timing of dividend payments affect stock prices, Dr. Lesser professed ignorance because he had not done any research as to the effect of forthcoming dividend payments on stock prices. (CILCO Cross Ex. 1, FIN-70; Staff Ex. 9.0, pp. 24-25) Again, this contradicts his direct testimony, which states, "…it turns out that the estimated [cost of equity] is sensitive to the assumption of when dividends are paid and increased, especially for the most common quarterly dividend payments." (CILCO Ex. 7.0 Rev., p. 31) Dr. Lesser's arguments regarding the expected dividend payments for the companies composing Ms. Phipps' LDC Sample are disingenuous and should not be given any weight in this proceeding.

c. CAPM

i. Risk-Free Rate of Return

Dr. Lesser claimed that Ms. Phipps' conclusion that the 4.88% U.S. Treasury bond yield is an upwardly biased estimator of the risk-free rate is logically inconsistent with her 5.7%-6.3% estimate of the long-term risk-free rate derived from economic forecasts. (CILCO Ex. 7.10 Rev., p. 15) Thus, he incorrectly concluded that Ms. Phipps' CAPM analysis reflects an inappropriate risk-free rate estimate that is biased downward. Dr. Lesser's criticism is misguided in two key respects.

First, Dr. Lesser wrongly concluded that Ms. Phipps believed a reasonable projection of the long-term risk-free rate is between 5.7% and 6.3%, or 6.0% on average. (CILCO Ex. 7.10 Rev., pp. 13-17) She did not. Rather, she combined forecasts of the components of the risk-free rate - expected inflation and real growth in gross domestic product - to estimate an implied long-term risk-free rate. The distinction between the actual and implied long-term risk-free rates is subtle but important.

Whereas the former directly reflects the expectations of investors, the latter does not. Consequently, the implied long-term risk-free rate is only a proxy for the actual, but unobservable, long-term risk-free rate. (Staff Ex. 9.0, p. 27) Proxies should be used with care, with their strengths and weaknesses assessed against other available data. As will be discussed below, the record demonstrates that Ms. Phipps recognized the limitations of both U.S. Treasury bond yields and economic forecasts as proxies for the unobservable long-term risk-free rate. Dr. Lesser did not.

Second, Dr. Lesser ignored his own testimony in which he recognized that U.S. Treasury bond yields are subject to interest rate risk. (CILCO Ex. 7.0 Rev., p. 42) Ms. Phipps explained that the nominal risk-free rate of return should reflect only the real risk-free rate plus a premium for expected inflation. However, due to relatively long terms to maturity, U.S. Treasury bond yields are also exposed to significant interest rate risk, thus a maturity risk premium is charged. Consequently, the U.S. Treasury bond yield that Ms. Phipps used to estimate the risk-free rate of return must represent an upper bound of the risk-free rate of return. If risky U.S. Treasury bond yields were lower than the risk-free rate of return, as Dr. Lesser argued, then risk premium models, such as the CAPM, which are based on the premise that investors require higher returns for higher levels of risk, would be invalid. Yet, financial theory indicates that investors are risk-averse; that is, investors require returns on their investments that are commensurate with the level of risk to which the investor is exposed. (Staff Ex. 3.0, pp. 18-19) Thus, Dr. Lesser's argument that the long-term risk-free rate exceeds 4.88% contradicts the fundamental relationship between risk and return.

Despite the maturity risk premium, the yield on U.S. Treasury bonds is currently below forecasts of the components of the long-term nominal risk-free rate. Obviously, a discrepancy exists between the real risk-free rate and inflation expectations embedded in U.S. Treasury bond yield. That is, those long-term forecasts differ from the expectations of the investing public (as reflected in U.S. Treasury bond yields), for investors are willing to accept a lower rate of return than the forecasts suggest. (Staff Ex. 9.0, p. 26)

Dr. Lesser's proposal, in his CAPM analysis, to use a forecasted U.S. Treasury bond yield that exceeds the current U.S. Treasury bond yield should be rejected. Although interest rates can rise or fall, it is impossible to foresee which will occur. This may be either detrimental or beneficial for a utility. For example, declining interest rates have been beneficial to CILCO. In Docket No. 94-0040, CILCO Gas' last rate proceeding, the Commission authorized a 9.24% overall cost of capital for CILCO Gas, which reflects a 7.34% cost of long-term debt and an 11.82% cost of equity. (Order, Docket No. 94-0040, December 12, 1994, p. 70) Although CILCO's cost of debt has declined to 5.98%, since December 1994, until the Commission authorizes a rate of return on rate base in the instant proceeding, CILCO Gas' rates continue to recover debt costs in excess of its current cost of debt. Just as the Commission could not foresee that interest rates would fall since CILCO Gas' last rate case, it cannot foresee whether the risk-free rate will even rise to, let alone above, the 4.88% yield on U.S. Treasury bonds used in Ms. Phipps' CAPM analysis.[7] Thus, the Commission should adhere to the precedent it has established in previous rate proceedings and rely on

[7] To reiterate, given the 30-year U.S. Treasury bond's exposure to interest rate risk, its yield exceeds the risk-free rate. (Staff Ex. 3.0, p. 23)

current U.S. Treasury yields rather than forecasts. (See Order, Docket No. 01-0444, MidAmerican Energy Company electric delivery services rate proceeding, March 27, 2002, pp. 15-16; Order, Docket Nos. 01-0465/0530/0637, Central Illinois Light Company electric delivery services rate proceeding, March 28, 2002, pp. 71 and 79; Order, Docket No. 99-0534, MidAmerican Energy Company gas rate proceeding, July 11, 2000, p. 32; Order, Docket Nos. 99-0122/0130, MidAmerican Energy Company electric delivery services rate proceeding, August 25, 1999, pp. 9-10; Order, Docket No. 94-0040, Central Illinois Light Company gas rate proceeding, December 12, 1994, p. 64)

ii. Market Rate of Return

Dr. Lesser argued that Ms. Phipps market rate of return estimate is fundamentally flawed because it allegedly violates the underlying assumptions of the CAPM, which dictate that the market rate of return represents the return on all risky assets, including stocks and bonds. (CILCO Ex. 7.10 Rev., p. 18) Once again, Dr. Lesser contradicted his direct testimony, in which he recognized that the S&P 500 is often used as a proxy for the market rate of return. Specifically, he testified that, “Rather than include every security in existence, which is the true definition of the ‘market’ portfolio, a composite index, such as the S&P 500 is often used.” (CILCO Ex. 7.0 Rev., p. 40) Ms. Phipps testified that although the S&P 500 is an imperfect proxy for the entire market of assets, it is very representative of the stock market. She noted that on March 31, 2003, the S&P 500 (a capitalization-weighted index of large capitalization stocks) had a market value representing 80% of the Wilshire 5000 (a capitalization-weighted index of all market-traded U.S. headquartered companies). (Staff Ex. 9.0, pp. 30-31)

Dr. Lesser also argued that estimating the market rate of return using only dividend-paying companies biases the estimate downward. (CILCO Ex. 7.10 Rev., pp. 18-19) Again, Dr. Lesser contradicted his direct testimony in which he stated that it is appropriate to include only dividend paying stocks to develop a market risk premium. (CILCO Ex. 7.0 Rev., p. 46) Furthermore, Dr. Lesser and Ms. Phipps both recognized that it is impossible to conduct a constant growth DCF model on non-dividend paying stocks. (CILCO Ex. 7.0 Rev., p. 46; Staff Ex. 9.0, p. 32)

Although Dr. Lesser disagreed with Ms. Phipps' market rate of return estimate, he used her market rate of return estimate in his CAPM and RPM analyses. (CILCO Ex. 7.10 Rev., pp. 32-33) Thus, for this reason, and those reasons set forth on pages 30 through 32 of Staff Exhibit 9.0, Dr. Lesser's testimony regarding Ms. Phipps' market rate of return estimate should not be given any weight in this proceeding.

iii. Beta Estimates

In her CAPM analysis, Ms. Phipps used an average beta estimate that reflects (1) the average Value Line beta for the companies composing her LDC Sample; and (2) a beta estimated from a regression analysis for the sixty months ending April 2003 ("regression beta"). The average Value Line beta for Ms. Phipps LDC Sample is 0.69. The regression beta for her LDC Sample is 0.52. (Staff Ex. 9.0, p. 5) In contrast, Dr. Lesser relied exclusively on the average Value Line beta for his Gas Sample. (CILCO Ex. 7.10 Rev., p. 32) Ms. Phipps described the Value Line beta estimation methodology and the regression methodology in Staff Exhibit 3.0 at pages 25 through 27.

Dr. Lesser alleged that Ms. Phipps' regression beta lacked econometric precision since estimating a regression beta for Ms. Phipps' LDC Sample results in a less precise average beta than estimating individual company betas. (CILCO Ex. 7.10 Rev., pp. 24-25) He also asserted that a single beta estimate for the LDC Sample would likely differ from an average of individual company beta estimates. (Id., at 24, Footnote 10) Ms. Phipps refuted these allegations by her calculations of individual beta estimates for each company composing her LDC Sample over the same measurement period that she used to calculate the LDC Sample beta estimates, using the same regression technique. As shown on Staff Exhibit 9.0, Schedule 9.7, the LDC Sample beta does not change when each company's beta estimate is calculated individually then averaged. Thus, Dr. Lesser's concerns in these regards are invalid. (Staff Ex. 9.0, p. 36)

Dr. Lesser also alleged that investors are more likely to rely upon Value Line betas than individual regression estimates such as those prepared by Ms. Phipps. (CILCO Ex. 7.10 Rev., p. 28) Once again, Dr. Lesser failed to substantiate that assertion. To the contrary, Ms. Phipps calculated her regression beta estimate using the Merrill Lynch methodology, which is recognized in financial literature as a valid beta estimation methodology. (Staff Ex. 9.0, p. 36) Furthermore, Ms. Phipps testified that she does not believe Value Line betas are more likely to be relied upon than her regression beta since other published betas are calculated using the Merrill Lynch methodology, including Multex.com. (Tr., at 333 and 335)

Ms. Phipps testified further that estimating a beta rather than relying on a published beta value is beneficial in that it permits one to review the output for anomalies; Value Line does not provide such information regarding its beta estimates. (Staff Ex. 9.0, p. 36) Ms. Phipps testified that regressions of betas should have an intercept value that is close to zero. An intercept value that differs substantially from zero indicates that there is a portion of risk that beta does not explain. The intercept value for Ms. Phipps' regression beta was very close to zero, which indicates that the beta estimate sufficiently explains the relationship between the market and those securities being evaluated. (Tr., at 338-339) Given that (1) both Value Line and the Merrill Lynch methodology beta estimates are widely accepted and disseminated to investors and that (2) the record does not indicate either source of estimates is flawed or superior to the other, Staff submits that both beta estimates should be used in the CAPM analysis.

d. Dr. Lesser's Risk Premium Model ("RPM")

Dr. Lesser testified that "Twelve [regulatory] agencies are shown to favor the Risk Premium methodology, which Ms. Phipps stated lacks a basis in financial theory." Ms. Phipps did not assert that the RPM has no basis in financial theory; rather she testified that Dr. Lesser's version of the RPM lacks a basis in financial theory. Specifically, Dr. Lesser's risk premium model (1) used a market-based beta value; (2) calculated a risk premium by subtracting AAA-rated bond yields from the market rate of return; and (3) added a beta adjusted risk premium to an A-rated bond yield. (CILCO Ex. 7.16) Dr. Lesser cited three sources that he claimed support his RPM. Ms. Phipps testified that those sources address risk premium models, but none of those sources support <u>Dr. Lesser's version of the RPM</u>. (Staff Ex. 9.0, pp. 38-40) Ms. Phipps also testified that none of her finance-related coursework addressed Dr. Lesser's risk premium model. (Tr., at 330)

Dr. Lesser also presented CILCO Exhibit 7.18, which provides a National Association of Regulatory Utility Commissioners' ("NARUC") 1995-1996 compilation of the methods accepted by state regulators, FERC and several Canadian provinces. (CILCO Ex. 7.17 Rev., pp. 5-6; CILCO Ex. 7.18) However, Dr. Lesser did not demonstrate that the RPMs referred to in CILCO Ex. 7.18 are the same RPM that he used to calculate CILCO Gas' cost of equity. (Tr., at 309-310) In fact, there is more than one form of the RPM as evidenced by Ms. Phipps' testimony, which recognizes two distinct risk premium models beyond the version Dr. Lesser employed. (Staff Ex. 3.0, p. 19; Staff Ex. 9.0, p. 39; Tr., at 313) Furthermore, Dr. Lesser testified that he has not confirmed that the jurisdictions referenced in CILCO Ex. 7.18 still use the methodologies indicated. (Tr., p. 311)

Dr. Lesser's RPM is almost identical to the CAPM except that it substitutes a risky debt rate for the risk-free rate. That substitution has no basis in financial theory. Dr. Lesser's RPM systematically overestimates the cost of equity for companies with betas less than one, as demonstrated on pages 41 and 42 of Staff Exhibit 3.0. In response, Dr. Lesser argued that the CAPM addresses systematic (i.e., undiversifiable) risk whereas his RPM directly incorporates both systematic and unsystematic (i.e., diversifiable) risk. (CILCO Ex. 7.0 Rev., pp. 47-48) Dr. Lesser rationalized further that it is not surprising the RPM may show a higher cost of equity than the CAPM since the RPM reflects diversifiable risk in addition to undiversifiable risk. (CILCO Ex. 7.10 Rev., p. 30)

The following example using Dr. Lesser's data demonstrates that Dr. Lesser's rationalization is invalid. Assume the following: (1) the risk-free rate of return is 6.0%; (2) the market rate of return is 14.29%; and (3) beta is 0.70. Inputting those values in the CAPM produces an 11.8% rate of return. (See CILCO Ex. 7.10 Rev., p. 32; CILCO Ex.

7.15) Assume further that the yield on A-rated bonds is 6.99%. (See CILCO Ex. 7.10 Rev., p. 33; CILCO Ex. 7.16) Inputting those values in Dr. Lesser's RPM produces a 12.1% rate of return. When beta is less than one, as it is in this example, Dr. Lesser's RPM produces a higher rate of return than the CAPM and his argument that his RPM captures additional risk (and thus, a greater return requirement) is not contradicted.[8] However, assume all of the factors remain the same, but the beta exceeds 1.0. If beta equals 1.50, the CAPM produces an 18.4% rate of return. On the other hand, Dr. Lesser's RPM produces a 17.9% rate of return. Thus, when the beta exceeds 1.0, Dr. Lesser's RPM produces a lower rate of return than the CAPM even though Dr. Lesser argues that the CAPM reflects only one type of risk whereas his RPM reflects all risk. The greater the risk, the higher the rate of return, but the greater risk that Dr. Lesser's RPM allegedly captures in comparison to the CAPM produces lower cost of equity estimates than the CAPM when beta is greater than one. Thus, Dr. Lesser's explanation for the differences in the cost of equity that his RPM and CAPM produce is contradicted and his RPM analysis should be rejected.

Moreover, Dr. Lesser's RPM estimated the equity risk premium using Aaa-rated bond yields. He then added that equity risk premium to an A-rated bond yield to estimate CILCO Gas' cost of equity. (CILCO Ex. 7.10 Rev., p. 33) Dr. Lesser's RPM uses bond yields of two different credit qualities, which upwardly biases his RPM cost of equity estimate. (Staff Ex. 3.0, p. 44) Yet, under cross-examination, Dr. Lesser testified, "The precise determination of a specific bond type does not materially affect the

[8] This example produces a lower cost of equity estimate than Dr. Lesser's 12.5% RPM-derived cost of equity estimate because Dr. Lesser's RPM uses two different bond yields, whereas Staff's example uses only the A-rated bond yield. Using two different bond yields in an RPM biases the cost of equity estimate upwards, as will be explained in the following paragraph.

methodological approach, as long as the equity premium is measured consistently between the selected bond rate." (Tr., pp. 313-314 and 317-318) Dr. Lesser echoed Ms. Phipps' testimony, which states, "Specifically, Dr. Morin's Regulatory Finance: Utilities' Cost of Capital notes that the choice of debt instrument used in the risk premium model must be applied consistently. (Staff Ex. 9.0, p. 39) Thus, Dr. Lesser's own testimony refutes the validity of his RPM analysis.

Ms. Phipps illustrated the upward bias that is created by using bond yields of different credit qualities in the RPM using Dr. Lesser's own data. (Staff Ex. 3.0, p. 46) Given Dr. Lesser updated his analysis in rebuttal testimony, Staff has updated the example that illustrates the upward bias created by mismatching bond yields in the RPM, using Dr. Lesser's data as presented on CILCO Exhibit 7.16. Subtracting the 6.42% prospective Aaa-rated bond yield estimate from Ms. Phipps' 14.29% market return that Dr. Lesser adopted in rebuttal testimony results in 7.87% equity risk premium estimate. (CILCO Ex. 7.16) Multiplying the market beta, which equals 1.0, by the 7.87% equity risk premium, results in a 7.87% market equity risk premium. Adding the market equity risk premium to Dr. Lesser's 6.99% A-rated bond yield estimate produces a 14.86% expected market return. (See CILCO Ex. 7.16) Thus, Dr. Lesser's improper RPM, which incorporates bond yields of two different credit qualities, estimates an expected market return that exceeds the one entered into the model by 57 basis points. This violates the principle that securities with the same risk (in this case, the market portfolio) have the same required rate of return. (Staff Ex. 3.0, p. 19)

Ms. Phipps testified that Dr. Lesser's RPM improperly measures a company-specific risk premium by multiplying beta by the difference between the market rate of return and the yield on Aaa-rated corporate bonds. Beta is a measure of market risk, which equals the difference between the market rate of return and the risk-free rate. Yet, Dr. Lesser's RPM measures market risk as the difference between the market rate of return and a corporate bond yield. That is, Dr. Lesser's RPM changes the market risk premium calculation, but holds the quantity of market risk, as measured by beta, constant. (Staff Ex. 9.0, p. 37)

Dr. Lesser testified, "Diversifiable, or company-specific risk, is reflected in the [risk premium] using an estimate of the prospective long-term bond yield for a company, because a company's bond rating reflects an assessment of all of the diversifiable business and financial risks a company faces." (CILCO Ex. 7.10 Rev., pp. 29-30) Dr. Lesser's statement is wrong. Since bond ratings reflect the risk that a company will default on its interest or principal payment obligations, and diversifiable risks would affect a company's ability to make those debt service payments, then bond ratings should reflect diversifiable risks. However, it does not follow that bond yields reflect diversifiable risks since bondholders, like stockholders, are able to reduce the level of risk inherent in their investments through diversification (e.g., holding a portfolio of bonds). Thus, contrary to Dr. Lesser's testimony, bond yields should not reflect diversifiable risks. (Staff Ex. 9.0, p. 38)

e. Analysts' Judgment

Regarding necessarily imperfect cost of equity models, Dr. Lesser stated, "Judgment will always be required… The absolutist view taken by Ms. Phipps fails to consider all of the other judgments that enter into such calculations, whether the choice of comparable companies, assumptions about earnings growth rates, stock betas, and so forth." (CILCO Ex. 7.17 Rev., p. 17) Notwithstanding Dr. Lesser's criticism, Ms. Phipps also recognized the importance of analysts' judgment in making cost of equity recommendations. Ms. Phipps testified that, "…because cost of common equity measurement techniques necessarily employ proxies for investor expectations, judgment remains necessary to evaluate the results of such analyses." (Staff Ex. 9.0, p. 28) The Commission has also recognized the importance of an analysts' informed judgment in a cost of equity analysis. (See Order, Docket No. 99-0534, MidAmerican Energy Company rate proceeding, July 11, 2000, p. 32; Order, Docket No. 94-0040, Central Illinois Light Company rate proceeding, December 12, 1994, p. 65) As Staff demonstrates in this brief, Ms. Phipps used sound judgment when choosing the companies for her LDC Sample, implementing the DCF model and the CAPM, evaluating the results of those analyses and making her final cost of equity recommendation for CILCO Gas. In contrast, Dr. Lesser's judgments were often unsound and contradictory. Dr. Lesser used an improper RPM, used improper inputs for his DCF model, CAPM and RPM, and mechanistically implemented those models without providing adequate support or basis for many of his assumptions.

i. Sample Selection

Dr. Lesser recognized that deciding whether a specific company is comparable to the company for which a cost of equity will be estimated requires judgment because comparability spans many attributes. (CILCO Ex. 7.17 Rev., pp. 12-13) Nonetheless, in forming his Gas Sample, Dr. Lesser strictly adhered to his sample selection criteria, including a criterion that requires at least 75% of revenues from natural gas operations. (CILCO Ex. 7.0 Rev., p. 23; CILCO Ex. 7.17 Rev., p. 13) When forming her LDC

Sample, Ms. Phipps used her sample selection criteria and her judgment. (Staff Ex. 3.0, pp. 12-13; Staff Ex. 9.0, pp. 2-3) In addition to the eight utilities included in Dr. Lesser's Gas Sample, Ms. Phipps' LDC Sample includes New Jersey Resources ("NJR") because its regulated gas business generates the vast majority of the company's earnings. Furthermore, the vast majority of NJR's assets are devoted to its regulated gas business. Thus, Ms. Phipps concluded that investors' future earnings depend predominantly on NJR's regulated gas business. (Staff Ex. 9.0, pp. 2-3) While Staff does not object to Dr. Lesser's decision to exclude NJR from his Gas Sample, Dr. Lesser's "absolutist" label is more applicable to his sample selection process than Ms. Phipps' process.

ii. DCF Analysis

Ms. Phipps examined the market movement for those days surrounding her stock price measurement date to ensure that the market did not fluctuate substantially on that date. (Tr., at 349) Additionally, Ms. Phipps estimated the expected dividend payments for her LDC Sample companies in a manner that more closely reflects utilities' typical practice of increasing dividends no more than once per year. (Staff Ex. 3.0, p. 17) Finally, Ms. Phipps evaluated each individual company's DCF-derived cost of equity estimate by calculating the mean and standard deviation of those results to ensure that her DCF-derived cost of equity estimate for the LDC Sample was reasonable (e.g., not skewed downward). (Tr., p. 349)

Conversely, Dr. Lesser's DCF analysis is flawed for several reasons. In his DCF analysis, Dr. Lesser erred when he (1) calculated an average historical stock price that employs an arbitrary stock price measurement period and substitutes obsolete stock price data for current data; (2) mismatched growth rate estimates and stock price data; and (3) calculated expected quarterly dividend payments in a manner that ignores the annual frequency of utility dividend increases. (Staff Ex. 9.0, pp. 10-11)

iii. Risk Premium Analysis

In her risk premium analysis, Ms. Phipps used judgment in estimating beta and choosing the appropriate proxy for the risk-free rate of return. To estimate beta through regression analysis, Ms. Phipps chose the Merrill Lynch methodology, which is widely recognized in financial literature. (Staff Ex. 9.0, p. 36; Tr., p. 335) She also evaluated the regression output to ensure that no anomalies were present that would result in a flawed beta estimate. (Tr., p. 336-337) To estimate the risk-free rate of return, Ms. Phipps compared U.S. Treasury bill and U.S. Treasury bond yields to economic forecasts of the real risk-free rate to determine which U.S. Treasury yield better reflects investor expectations of the risk-free rate of return. (Staff Ex. 3.0, pp. 22-23; Staff Ex. 9.0, p. 4) Ms. Phipps' analysis also recognizes the limitations associated with forecasted economic data as direct proxies for investor expectations. (Staff Ex. 9.0, pp. 26-27)

In contrast, Dr. Lesser's CAPM analysis is flawed because Dr. Lesser erred when he (1) ignored an observable proxy of the risk-free rate of return (i.e., U.S. Treasury bond yield) and instead used a proxy that does not directly reflect investor expectations (i.e., economic forecasts); and (2) used an incorrect beta value for Laclede Group. Dr. Lesser also erred when he used a RPM that lacks a basis in financial theory, improperly applied a market risk premium-based beta to a non-market risk premium, and used two different types of corporate bond yields despite acknowledging that practice is incorrect. (Staff Ex. 9.0, p. 11; CILCO Ex. 7.16; Tr., pp. 313-314 and

317-318)

Dr. Lesser also used poor judgment when he employed Value Line betas in his CAPM and RPM analyses without understanding how Value Line estimates beta. As presented in Ms. Phipps' testimony, Value Line uses weekly price data to estimate beta. (Staff Ex. 3.0, p. 26) However, Dr. Lesser testified that, "Commercial firms, such as Value Line and Zack's, commonly use 60 months' price movement data to estimate these regressions." (CILCO Ex. 7.0 Rev., p. 40)

f. U.S. Supreme Court's Hope and Bluefield Decisions

Dr. Lesser testified that, "Rather than engaging in a detailed refutation of every point of apparent disagreement, I focus on a broader view of the differences in [Ms. Phipps' and my] analytical approaches to estimating a fair return on common equity, and the context in which I have used my approach." (CILCO Ex. 7.17 Rev., p. 2) The "context" to which Dr. Lesser refers is two U.S. Supreme Court decisions that address estimating regulated utilities' cost of equity: Bluefield Water Works and Hope Natural Gas. Dr. Lesser states further, "Fundamentally, therefore, the goal in this proceeding should be to determine an allowed [cost of equity] estimate that is reasonable and fair, while recognizing the inherent uncertainty in doing so." (CILCO Ex. 7.17 Rev., p. 5) Dr. Lesser then refers to a reasonableness standard established by the Supreme Court twelve more times throughout his surrebuttal testimony. (See CILCO Ex. 7.17 Rev., p. 6-12 and 15-17) Dr. Lesser makes a legal interpretation of Supreme Court decisions although he is neither an attorney nor a legal expert. (See CILCO Ex. 7.1) Thus, Dr. Lesser's testimony regarding the "reasonableness" his cost of equity estimate should be given no weight in this proceeding.

Dr. Lesser also testified that in estimating the cost of equity, decision-making bodies should be more concerned with whether the outcome would be sufficient to maintain the financial integrity of a utility than specific calculations. (CILCO Ex. 7.17 Rev., p. 17) Yet, Dr. Lesser presented no analysis or rationale supporting his opinion that Ms. Phipps' recommended 10.47% cost of equity would not allow CILCO Gas to maintain its financial integrity. (Tr., p. 316 and 320) In contrast, Ms. Phipps recognized that because cost of common equity measurement techniques necessarily employ proxies for investor expectations, judgment remains necessary to evaluate the results of such analyses. (Staff Ex. 3.0, p. 28) Thus, along with DCF and risk premium analyses, Ms. Phipps considered the observable 6.19% rate of return the market currently requires on less risky A-rated long-term debt in comparison to her recommended 10.47% cost of equity for CILCO Gas. (Staff Ex. 9.0, p. 6)

g. Flotation Cost Adjustment

CILCO witness O'Bryan testified that CILCO has incurred $2,273,429 in issuance costs that remain unrecovered. (CILCO Ex. 8.0 Rev., p. 5; CILCO Ex. 8.2) That amount is consistent with the amount that the Commission allowed CILCO a return on, but not recovery of, in the Company's last three rate cases. (Order, Docket No. 94-0040, December 12, 1994, at 68; Order, Docket Nos. 99-0119/0131 Consolidated, August 25, 1999, p. 41) In Docket Nos. 01-0465/01-0530/01-0637 Consolidated, CILCO's electric delivery services rates proceeding, both Staff and CILCO proposed flotation cost adjustments. Nevertheless, the Commission, in its role as finder of fact, did not allow CILCO a flotation cost adjustment to its cost of common equity. The Commission Order states, "Having reviewed the record on this issue, the Commission finds that CILCO has not demonstrated that a flotation cost adjustment should be made to its cost of equity." In the instant proceeding, CILCO did not provide any additional evidence that a flotation cost adjustment should be made to its cost of common equity. (Staff Ex. 3.0, p. 30) Thus, the Commission should only allow CILCO a flotation cost adjustment if the Commission is persuaded that the evidence that it deemed insufficient in Docket Nos. 01-0465/01-0530/01-0637 Consolidated is now sufficient.

Should the Commission authorize a flotation cost adjustment in the instant proceeding, it should be calculated using the formula set forth on page 30 of Staff Exhibit 3.0, which is the same formula used in the last three CILCO rate proceedings. Specifically, it should reflect Ms. Phipps' 10.47% cost of equity recommendation; issuance costs totaling $2,273,429; and CILCO's June 30, 2002, common equity balance. This would result in a seven basis points flotation cost adjustment for CILCO. Mr. O'Bryan agreed with Ms. Phipps' calculation of the flotation cost adjustment. (CILCO Ex. 8.3, p. 4)

D. Overall Rate Of Return On Rate Base

CILCO accepted Staff's proposed June 30, 2002 capital structure. (CILCO Ex. 8.3, p. 2) CILCO's June 30, 2002, capital structure in conjunction with CILCO's recommended 11.73% cost of equity, results in an 8.73% overall cost of capital for CILCO Gas. Staff recommends an 8.12% overall cost of capital that reflects a 10.47% cost of common equity, as shown on Appendix B. (Staff Ex. 9.0, Sch. 9.1) The record demonstrates that Staff's cost of equity recommendation is based upon the valid application of sound financial theory, while CILCO's is not. Therefore, the Commission should adopt Staff's recommendations, as presented on Appendix B, to set rates in this proceeding.

V. COST OF SERVICE STUDY- UNCONTESTED

The Company requested an overall increase in CILCO's gas revenues of 5.11%. CILCO used a Cost of Service Study ("COSS") provided by Navigant Consulting, Inc. ("NCI"). (CILCO Ex. 1.0, p. 4) This COSS was provided to Staff for analysis. The Company has stated that the "2001 COSS primarily follows the methodologies approved by the Commission in the Company's last gas rate case, Docket No. 94-0040." (CILCO Ex. 3.0, p. 3) The Company states that the results of the cost study should be used "as a guide in the development of unit rates." (Id., at 5) The Company is not proposing to go to fully cost-based rates at this time."

Staff reviewed the COSS for compliance with the Commission's Order in CILCO's most recent rate case (Docket No. 94-0040, Dec. 12, 1994) and for general rate design factors. Staff witness Harden did not find any discrepancies in the data that was analyzed and reviewed in the COSS provided by CILCO.

VI. RATE DESIGN

A. Uncontested Issues

1. Discontinuance of Rate 500 and Rate 900

The Company proposed and Staff witness Harden agrees with the discontinuance of Rate 500, Pilot Residential Gas Transportation Service and Rate 900, Yard Lighting Service. (CILCO Ex. 4.0, p. 3)

2. Reclassification of Rate 550 and Rate 600

Uncontested proposals were made for changes in Rate 550, Rate 600, Rate 650, Rate 700, and Rate 950. No proposal was made to change the contracts that are already effective under Rate 800.

The Company is reclassifying some customers under Rate 550 and Rate 600. (CILCO Ex. 4.0, p. 3) Staff and the Company have agreed that 700 cfh is the appropriate breaking point between the classes and the Company agreed to a flat delivery charge in these two classes. (ICC Staff Ex. 10.0R2, p. 1)

Staff and the Company also agree on the design for Rate 650, Intermediate General Gas Service and Rate 700, Large General Gas Service. The COSS customer charge has been adjusted by the percentage change between Staff's recommended revenue requirement and the Company's proposed revenue requirement and then set the customer charge close to cost. Staff witness Harden then took the targeted revenue for this customer class and subtracted the customer charge revenues to arrive at the recommended demand and distribution charge revenues which then were divided by the annual billing determinants to develop the rates recommended by Staff for Rate 550, 600, 650 and 700. (Staff Ex. 4.0R, p. 12)

Rate 950, Standby and Reserve Gas Service has been eliminated as recommended by Staff witness Ianello. (CILCO Ex. 4.4, p. 10)

3. General Terms and Conditions

Staff agrees to the changes to the General Terms and Conditions as discussed by CILCO witness Turner.

Section 1.120 - eliminated the definition of "limited firm backup" from Definition of Terms and from Rider T1, T3, T5 and T7. (CILCO Ex. 2.0, p. 2)

Sections 2.100 and 2.110 – additional language from part 280.60 (a) and (b) that relates to a deposit being required if tampering has occurred and the customer benefited. (CILCO Ex. 2.0, p. 3)

Section 2.130 – proposing to modify language to be more descriptive of the situations in which the Company assesses a charge for non-sufficient funds transactions made by the customer. (CILCO Ex. 2.0, p. 4)

Section 4.110 – provision to disclaim responsibility for pipes and equipment located on the customer's premises. (CILCO Ex. 2.0, p. 3)

Section 5.110 and 5.115 - deleted municipal tax language that is no longer applicable and renumbered subsequent sections. Also deletes unnecessary language that refers to House Bill 362. (CILCO Ex. 2.0, p. 5)

4. Transportation Specific Administrative Charges

The Company originally proposed additional transportation specific administrative charges in Rider T of $13.00 and $30.00. Staff witness Iannello recommended the largely fixed administrative costs associated with the provision of transportation service across all customer classes that are eligible to take transportation service. These classes include Rate 550 - Small General Gas Service, Rate 600 - General Gas Service, Rate 650 - Intermediate General Gas Service, and Rate 700 - Large General Gas Service. Mr. Iannello recommended that the costs be allocated based on each rate class' share of the total number of transportation customers. (Ex. 6.0 R-2, p. 15-17) The Company adopted Mr. Iannello's proposal, and no other party opposed this proposal. (CILCO Ex. 4.4 Rev., p. 10)

B. Contested Issues

1. Customer Charge

The Company currently has a $9.85 customer charge, for residential customers on Rate 510, which in the last rate case was 63.2% of the $15.58 cost of service to provide residential customers service. (CILCO Ex. 4.8, p. 5) In direct testimony the Company proposed a $10.50 customer charge which was 64% of the cost of $16.34 to provide the service to residential customers. (CILCO Ex. 4.2, p. 1 and CILCO Ex. 3.3, p. 4) Staff witness Harden recommends the Company increase the customer charge to 75% of the cost-based customer charge as the Company should be working toward full cost of service. (Staff Ex. 4.0R, p. 5) The customer charge for the other rate classes are all above 97% of the cost to provide the service to those individual classes. In surrebuttal testimony the Company did propose a customer charge that is 75% of the cost to provide the service. (CILCO Ex. 4.6, p. 1)

2. Rate 510 Delivery Charge

At this time Rate 510 has a 2-part declining block structure for the delivery charge. (CILCO Ex. 4.3, p. 1) The dividing point between the two blocks is set at 90 therms per month. Under this structure, the first 90 therms of gas are priced at a higher rate than subsequent usage. In other words, as consumers move into the higher block, the per-therm price declines. The declining block structure does not convey to ratepayers the proper price signals to conserve energy. This lower tail block rate serves as an incentive for ratepayers to increase their gas consumption. This is not an appropriate price signal to send customers. The rates should be designed to encourage ratepayers to conserve. Conservation is necessary because there is a consumption cost that is not directly captured in the price of gas. That cost is an environmental cost.

Each therm of gas consumed has an adverse effect and thereby creates a cost to the environment. This is a cost paid by society as a whole. To the extent that ratepayers conserve, there will be less costs to the environment and society, as a whole, will benefit. (Staff Ex. 4.0, p. 6)

Staff witness Harden proposes replacing CILCO's declining rate block proposal with a flat delivery charge for Rate 510, Residential Gas Service. (Staff Ex. 4.0, p. 9) The flat rate sends a more consistent price signal to consumers because it does not reward higher usage with a lower unit rate. By removing this incentive, the proposed delivery rate encourages ratepayers to conserve, rather than consume. And to the extent that ratepayers do curb their consumption, the environmental cost will decline.

The Company opposes a flat delivery charge unless the customer charge is fully recovering the cost to provide service at 100% instead of the proposed 75%. (CILCO Ex. 4.4, p. 13)

3. Grain Drying Rate

Staff did not provide testimony on the grain dryer rate suggested on behalf of BEAR by Witness Lee Smith. The only concern that Staff would raise is in the development of a rate for a specific type of business. This rate can be developed but is it not typical to do so as at this time only Illinois Power has a rate for grain dryers. (BEAR Ex. 1, p. 2)

BEAR witness Smith compiled data from 13 consumers and estimated there were 57 possible customers for the grain dryer rate. (BEAR Ex. 1, p. 8 and Bear Ex. 2, p. 2) A thorough analysis by the Company would allow the Commission and other interested parties to take a look at the possibility of a grain dryer rate for CILCO in the next rate case. If the Commission believes that a rate for CILCO's grain dryer customers may be appropriate, the Commission should direct the Company to provide the necessary information such as load shape, meter size, usage, demand allocator factors and other characteristics of the customer group in the Company's next rate case. At the time of the next rate case the Company could decide if it wanted to present a grain dryer rate or provide arguments as to why this rate would not be appropriate along with all the gathered information.

4. Allocation of Storage Costs/Bank Capacity

A fundamental issue in the instant proceeding is the allocation of storage related costs and access to storage for balancing, peaking, and seasonal hedging. The Company, Staff, and IIEC generally agree that there are three functions of storage: balancing, peaking, and "supplemental supply" or seasonal hedging.

Mr. Iannello described the benefits associated with these three functions. First, Mr. Iannello argued that storage provides a seasonal hedge by allowing shippers to inject gas into storage during the injection season (roughly April through October), when spot prices are typically lower, and withdraw gas from storage during the withdrawal season (roughly November through March), when spot prices are typically higher. (Ms. Seckler and other witnesses refer to the seasonal hedging function as "supplemental supply" and the terms are used interchangeably in this brief). Second, Mr. Iannello argued that storage facilities provide a balancing function, allowing shippers to reconcile imbalances between usage and deliveries. Third, Mr. Iannello stated that storage could reduce the need for more expensive pipeline capacity during periods of peak demand. (Staff Ex. 12.0, p. 4)

In the instant proceeding, the Company proposes to allocate storage plant and related expenses equally to both sales and transportation customers in each rate class. The Company provided an analysis determining the use of storage for each of the functions identified above. The Company's analysis assigned 60% of total storage costs to the supplemental supply or seasonal hedging function, 8% to the peaking function, and 32% to the balancing function. (CILCO Ex. 5.0, p. 10) No party disputed this cost assignment. However, the Company's proposed limitations on storage banks in Rider T, Transportation Service, do not allow transportation customers to realize an appropriate level of benefits from the use of storage given the Company's proposed allocation of storage plant and related expenses. The Company fails to tie the storage flexibility provided to transportation customers to its proposed storage cost allocation. Staff witness Iannello recommended several modifications to the rules governing transportation service in Rider T to reconcile the Company's storage cost allocation and the rules governing transportation customer bank use in Rider T. (Staff Ex. 6.0 R-2, pp. 21-22)

Like Staff witness Iannello, IIEC witness Mallinkcrodt identified the disparity between storage cost allocation and the rules governing transportation service in Rider T. However, instead of recommending adjustments to the rules governing the use of transportation customer banks, Mr. Mallinkcrodt recommended an adjustment to the Company’s proposed rate design by reallocating storage related costs from transportation customers to sales customers to reflect the Company's proposed limitations on transportation customer access to storage.

In direct testimony, both Mr. Iannello and Mr. Mallinkcrodt argued that the rules governing transportation service in the Company's proposed Rider T provide transportation customers with an acceptable level of balancing but failed to provide appropriate access to storage for peak shaving. Further, Mr. Iannello questioned whether the Company's proposed Rider T provided transportation customers with access to storage for seasonal hedging and Mr. Mallinkcrodt argued that the Company's proposed Rider T failed to provide access to storage for seasonal hedging. (Staff Ex. 6.0 R-2, pp. 9, 12-15) Both Mr. Iannello and Mr. Mallinkcrodt made recommendations to remedy the inequity between the Company's proposed storage cost allocation and the rules governing the use of transportation customer banks. These recommendations are discussed below.

a. Storage Peaking and MDBW

Under current tariff provisions, transportation customers are denied access to their positive bank balances on Critical Days, and banks are sometimes frozen, denying transportation customers access to their bank for extended periods. These tariff provisions restrict the ability of transportation customers to use their banks for peak shaving. In the instant proceeding, the Company proposes to provide transportation customers with access to their bank on Critical Days and remove the tariff provision that allows the Company to freeze banks. (CILCO Ex. 5.0, pp. 13-14) No party opposed the Company's proposal to eliminate the tariff provision that allows the Company to freeze banks. However, Staff raised concerns over the Company's proposed MDBW.

The MDBW defines the amount of positive bank balance that a customer can access on a critical day. In direct testimony, the Company proposed to calculate the MDBW by dividing a customer's positive bank tolerance by 30. (CILCO Ex. 5.0, p. 14)

The Company's proposed MDBW was not tied to the storage costs that were allocated to transportation customers nor consistent with the amount of Company deliveries to customers that come from storage. Because the Company proposed to assign storage costs based on the various functions including the peaking aspect of storage and because such costs are allocated equally across sales and transportation customers in the same rate classes, Staff witness Iannello recommend tying the MDBW to the amount of gas that the Company plans to withdraw from on-system storage on a forecasted peak design day. (Staff Ex. 6.0 R-2, pp. 12-13) The Company adopted Mr. Iannello's proposed formula for calculating the MDBW with two modifications. (CILCO Rebuttal Ex. 5.2, pp. 9-10) The first modification accounted for a 15,000 Mcf emergency reserve requirement. This resulted in an MDBW of 50% of a customer's peak day demand. The Company also recommended that the MDBW be applied to a customer's peak day demand or maximum daily contract quantity depending on the customer's rate classification. Mr. Iannello accepted the Company's modifications to his proposed MDBW (Staff Ex. 12.0, p. 16). No party opposed Mr. Iannello's proposed MDBW as modified by the Company. (Discussion of the MDBW issue was included in the Rate Design section of this brief because it is tied to the storage costs that are allocated to transportation customers and the storage flexibility afforded to transportation customers.)

In light of the Company's adoption of Mr. Iannello's proposed MDBW, Mr. Mallinkcrodt adjusted his proposed storage cost allocation to reflect the increase in access to storage for peak shaving that transportation customers would receive from the more liberal MDBW. In rebuttal testimony, Mr. Mallinkcrodt proposed to reallocate only the portion of storage related costs attributable to the supplemental supply (seasonal hedging function). (IIEC Ex. 2.0, p. 5)

b. Seasonal Hedging and Bank Allocation

Mr. Iannello questioned whether the Company's proposed Rider T provided transportation customers with appropriate access to storage for seasonal hedging. Despite a specific request in Mr. Iannello's direct testimony, the Company failed to demonstrate that transportation customers could use storage for seasonal hedging in the same manner that the Company uses storage for seasonal hedging to serve sales customers. The Company provided no support for its proposed allocation of ten days of bank capacity to transportation customers.

In order to rectify the inequity in the Company's proposed allocation of seasonal hedging related storage costs and bank limitations that prevent transportation customers from using storage for seasonal hedging, Mr. Iannello recommended tying the allocation of storage bank capacity to seasonal throughput - the same allocator that the Company used in its cost of service study to allocate seasonal hedging costs associated with storage. (Staff Ex. 12.0, pp. 7-8) Seasonal throughput is measured as usage during the period of December through March. Rather than providing transportation customers with the arbitrarily determined ten days of bank capacity in the Company's proposed Rider T, Mr. Iannello recommended calculating a transportation customer's bank capacity based on the ratio of annual on-system storage withdrawals to seasonal throughput on the Company's system. This ratio, when applied to an individual transportation customer's seasonal throughput, would yield the customer's allocated bank capacity. It provides a bank that would allow the same share of gas usage in the winter period from storage as is provided to sales customers. (Staff Ex. 12.0, pp. 7-8)

Mr. Iannello used annual system withdrawals for the test year 2001, as reported by the Company in its response Staff data request ENG 1.8, to calculate the numerator of the ratio. (Staff Ex. 12.0, pp. 7-8) Annual withdrawals for on-system storage in 2001 totaled approximately 62,142,230 therms. Seasonal throughput on the Company's system for the test year 2001, as reported by the Company in its cost of service study, was used to calculate the denominator of the ratio. Seasonal throughput in 2001 was 275,451,631 therms. The ratio of on-system storage withdrawals to system seasonal throughput (62,142,230/275,451,631 or approximately 22.5%) would be included in Rider T and multiplied by each transportation customer's seasonal throughput (i.e. throughput during the period of December through March) to determine each transportation customer's bank capacity. (Staff Ex. 12.0, pp. 7-8) In response to concerns that some customers may not use gas during the period of December through March and, thus, would not be allocated any bank capacity, Mr. Iannello recommended that all customers be allocated a minimum of five days of bank calculated in the same manner as the Company's proposed bank allocation. (Tr. 169)

Mr. Iannello stated that his approach was desirable because it does not require a determination and reallocation of costs (from transportation to sales customers) associated with the seasonal hedging function of storage. His approach also ensures that transportation customer access to storage for seasonal hedging mirrors the seasonal hedging capability of on-system storage facilities that transportation customers pay for under the Company's proposed allocation of storage plant and related expenses. Finally, using system data to calculate the allocation of on-system storage capacity for seasonal hedging is consistent with the use of that data to calculate transportation customer access to on-system storage on critical days, which the Company had already adopted. (Staff Ex. 12.0, p. 8)

In defense of the Company's proposed allocation of bank capacity and storage cost allocation, Company witness Seckler claimed, “The storage analysis performed by the Company found that there is essentially no difference in the storage service functions provided to a transportation customer and those provided to a sales customer.” (CILCO Ex. 5.2, p. 2) However, the Company provided no "storage analysis" that compares the storage service functions provided to transportation customers to the storage service functions provided to sales customers. Further, the storage service originally proposed by the Company failed to provide transportation customers with equivalent access to storage for peak shaving. (Staff Ex. 6.0 R-2, pp. 12-13) The Company recognized this inequity by adopting Staff's proposed MDBW but failed to rectify the inequitable allocation of storage costs related to seasonal hedging and bank capacity. (CILCO Rebuttal Ex. 5.2, pp. 9-10)

Ms. Seckler, in rejecting any proposal to reallocate storage related costs away from transportation customers or provide greater access to storage for seasonal hedging, claims that the Company is providing a supplemental supply function to transportation customers whenever their daily usage does not match their daily delivery to the Company’s system. (CILCO Rebuttal Ex. 5.2, p. 3) However, Mr. Iannello pointed out that Ms. Seckler was describing a balancing function not a "supplemental supply" or seasonal hedging function. To the extent that a customer's daily nomination does not match its daily usage, the customer relies on its bank balance to offset differences between deliveries and usage. The customer's bank balance is available to the Company for reconciling daily imbalances on the system and, thus, serves a balancing function rather than a supplemental supply function. (Staff Ex. 12.0, pp. 9-10)

5. Carrying Costs of Working Gas in Storage

When a shipper, such as a utility, transportation customer, or third-party supplier, stores gas in underground storage for use during later periods, the shipper incurs a cost equal to the rate of return that could otherwise be earned on the investment in storage gas. The Company maintains working gas inventory that is eventually withdrawn from storage and used to serve sales customers. (Staff Ex. 12.0, p. 10)

In the instant proceeding, the Company has estimated its carrying cost of working gas in storage and proposed to recover this cost equally from both sales and transportation customers through base rate delivery charges. (Staff Ex. 6.0 R-2, p. 7) Staff witness Iannello argued that it is inappropriate to allocate the Company's carrying cost of working gas in storage to transportation customers because transportation customers do not use the Company's working gas. (Staff Ex. 6.0 R-2, p. 8) Rather, transportation customers inject their own working gas into storage. The Commission recognized this when it previously identified reductions in a utility’s carrying cost of gas in storage as a result of customers choosing transportation service over sales service. In Docket Nos. 00-0620/00-0621 (Consolidated) Nicor Gas Company’s Customer Select Program, Docket No. 01-0469 North Shore Gas Company’s Choices For You Program, and Docket No. 01- 0470 Peoples Gas Light and Coke Company’s Choices For You Program, the Commission ordered the utilities to provide credits associated with a reduction in the carrying cost of gas in storage as a result of sales customers migrating to transportation service. (Staff Ex. 6.0 R-2, p. 8)

IIEC witness Mallinkcrodt supported Mr. Iannello's proposal to allocate all of the carrying costs of working gas in storage to sales customers only. (IIEC Ex. 2.0, p. 13) In addition, Mr. Iannello states that suppliers and end-use customers store gas for future use because the carrying costs (and any other related costs) are offset by the benefits of having supply to meet unexpected demand swings, reduce reliance on pipeline capacity during periods of peak demand, and substitute for market purchases during relatively high priced periods. (Staff Ex. 12.0, p 11) Thus, end-users benefit when they or their supplier incur the carrying costs of working gas stored.

Sales customers benefit when the Company stores gas because the Company's Purchased Gas Adjustment ("PGA") charges are lower due to the seasonal hedge that storage provides. Transportation customers, on the other hand, receive no benefit when the Company stores its gas. When a transportation customer purchases Company-supplied gas, the Company's tariff requires transportation customers to purchase gas at the market price when market prices are higher than the PGA rate. That is, when PGA gas is priced lower than spot market gas due to the seasonal hedge that storage provides to the PGA, transportation customers do not have access to lower cost PGA gas, and, therefore, do not benefit from the Company's use of storage. When market prices are below the PGA rate, transportation customers pay the full PGA rate, making a net contribution to PGA costs for gas that the Company obtains in the spot market. (Staff Ex. 12.0, pp. 11-12) Therefore, the Company's carrying cost of gas in storage should not be allocated to transportation customers.

In response to Mr. Iannello's recommendation, Ms. Seckler argues that the Company incurs carrying costs associated with working gas in storage on behalf of both sales and transportation customers. Ms. Seckler states, "It must be recognized that the inventory of working gas in the storage fields is necessary to provide pressure to permit effective withdrawal of gas from storage." (CILCO Ex. 5.2, p. 8) While it is true that minimum storage inventory levels must be maintained to ensure deliverability, transportation customers make their own contribution to the amount of working gas in the Company's on-system storage by delivering volumes in excess of their usage and maintaining positive bank balances. These bank balances offset the Company’s need to maintain working gas inventory on behalf of transportation customers, contribute to the total volume of working gas inventory, and allow the Company to maintain deliverability of on-system storage. When customers switch from sales service to transportation service, they directly assume the responsibility of the carrying cost of banked gas. (Staff Ex. 12.0, p. 11)

Ms. Seckler claims that, in the absence of a requirement for transportation customers to provide storage gas that the Company can manage to ensure reliable operation, the Company still needs to supply some level of working inventory on behalf of transportation customers. (CILCO Rebuttal Ex. 5.2, p. 8) However, Staff disagrees. (Staff Ex. 12.0, pp 12-13; Staff Ex. 12.1). Disregarding the fact that sales customers are the sole recipients of any benefits associated with the gas that the Company stores, it appears that Ms. Seckler’s arguments are based on the behavior of individual transportation customers or a select group of transportation customers. Ms. Seckler isolates the activity of one customer or a select group of transportation customers at specific points in time in a misguided attempt to demonstrate that transportation customers as a group fail to maintain the necessary level of working gas in storage. However, diversity across all transportation customers mitigates large swings in aggregate transportation customer bank balances. That is, one transportation customer or a small subset of transportation customers may significantly draw down or build up their banks during the course of a month, but the aggregate activity of all transportation customers is likely to result in a fairly stable balance of stored gas on the Company's system.

Exhibit 12.1, attached to Mr. Iannello's rebuttal testimony, tracks transportation customer activity for the period of January 2000 through December 2002. Exhibit 12.1 demonstrates that transportation customers rarely rely on system gas to meet their needs. When system gas is purchased it is a small amount relative to the aggregate usage of transportation customers. Furthermore, transportation customers have maintained a fairly sizable aggregate bank balance throughout the course of the three-year period, and the bank balance never comes close to being drawn down to zero. (Staff Ex. 12.0, p. 13)

In reference to Mr. Iannello's proposed reallocation of the carrying costs associated with working gas in storage, Ms. Seckler claims, "…a simplistic crediting approach will place more financial risk and expense on the Company and its non-transporting customers." (CILCO Rebuttal Ex. 5.2, pp. 8-9) However, Mr. Iannello does not recommend a "simplistic crediting approach". (Staff Ex. 12.0, pp.14-15) Rather, Mr. Iannello recommends allocating all of the costs associated with the carrying cost of working gas in storage to sales customers only.

Under Mr. Iannello's proposal, a separate set of delivery charges would be developed for transportation customers and sales customers in each rate class. The carrying costs associated with working gas in storage would be allocated entirely to sales customers and recovered through the sales customer delivery charges in each rate class. (Staff Ex. 12.0, p. 15)

Mr. Iannello's proposal would not place the Company and its sales customers at any additional financial risk despite such claims by Ms. Seckler. (CILCO Ex. 5.2, p. 8) If sales customers migrate to transportation service, the Company's revenues would decrease due to the difference in delivery charges for sales and transportation customers. However, the Company's carrying cost of working gas in storage would also decrease because the Company would be relieved of its obligation to maintain working inventory and incur carrying costs on behalf of those customers. The customers would directly assume the carrying cost of gas in storage when they switch to transportation service, relieving the Company of the obligation to maintain working gas inventory and incur the associated carrying costs. Therefore, the Company and its sales customers should be indifferent as to the number of customers that switch from sales to transportation service.

VII. TARIFF TERMS AND CONDITIONS

A. Uncontested

1. Maximum Daily Bank Withdrawal

As mentioned above, the Company adopted Mr. Iannello's proposed formula for calculating the MDBW with two modifications. (CILCO Ex. 5.2, pp. 9-10) The first modification accounted for an emergency storage reserve requirement. This resulted in an MDBW of 50% of a customer's peak day demand. The Company also recommended that the MDBW be applied to a customer's peak day demand or maximum daily contract quantity depending on the customer's rate classification. Mr. Iannello accepted the Company's modifications to his proposed MDBW (Staff Ex. 12.0, p. 16). No party opposed Mr. Iannello's proposed MDBW as modified by the Company.

2. Penalty Charge and Cash Out Procedures

The Company proposed to increase the penalty charge to both transportation and sales customers for failure to curtail gas use from $1 per therm to $6 per therm. This increase is consistent with similar charges that the Commission has approved in other Illinois gas utility tariffs. The Company also proposed cashout provisions for excess bank balances. No Party objected to either of these proposals. (CILCO Ex. 5.0, pp. 15-16)

3. Elimination of Rate 950 – Standby Service

Under the current CILCO tariff, the Company requires any non-residential customer using gas on a firm basis as a standby or reserve fuel for use in the event of disruption of some other source of fuel or energy supply to take service under Rate 950 - Standby and Reserve Gas Service (“Rate 950“). On pages 18 through 22 of his direct testimony, Staff witness Iannello stated his concerns with the overall design and applicability of Rate 950. Mr. Iannello argued that rising concerns over the reliability of electric transmission and distribution systems and artificial barriers to entry for distributed generation require a closer look at Rate 950.

Mr. Iannello recommended that Rate 950 be eliminated from the Company's tariff and customers that are currently being served under Rate 950 be served under the applicable standard rate. This would also require the removal of language in the Availability section of Rate 550, Small General Gas Service, and Rate 600, General Gas Service, that prohibits customers requiring standby or reserve gas service from taking service under those rates. (Staff Ex. 6.0R-2, p. 21)

Mr. Stillson states that the Company is "receptive" to Staff witness Iannello's proposal regarding Rate 950. (CILCO Ex. 4.4 Rev., p. 10) Instead of eliminating Rate 950 altogether, the Company proposes to "…remove language from the Availability sections of Rates 550 and 600 that prohibits customers requiring standby or reserve gas service from taking service under those rates." In addition, the Company proposes to add language to the Availability sections that specifies that the Company is not obligated to provide standby or reserve gas service under these rates if, in the Company's sole judgment, sufficient main capacity does not exist to provide the service. (CILCO Ex. 4.4 Revised, p. 10) No party objected to the Company's proposed treatment of standby and reserve gas customers or the Company's proposed change in tariff language.

B. Contested

1. Installations of New Services

Staff recommends the Company revise its existing tariff language to require the Company to install new services in 15 working days or less except under certain extenuating circumstances not under the control of the Company. (Staff Ex. 11R, pp. 14-15) The Company disputes the need for this provision.

Staff noted that the Company's existing and proposed tariff, in the General Terms and Conditions – Conditions of Service, under Section 4.180 Delays and Interruptions of

Service, included a provision that notes, in part, that "The Company shall endeavor to provide service connections to new customers within a reasonable time…". (Staff Ex. 5, p. 11) However, the Company's tariffs do not define the phrase "within a reasonable time". (Id., at 12) Staff recommends a revision to this portion of the Company's tariff so that a set amount of time was clearly indicated. Specifically, Staff recommends the Company's tariff specify that it would install new services, in 15 working days or less.

Staff had three reasons for selecting the 15 working day time limit. First, Staff indicated that the 15 working days should provide the Company enough time to receive the service request, schedule the work, and complete the installation without undue haste. (Id., at 13)

Second, the Company indicated in its response to Staff data request ENG 1.24 that once the customer is ready for service, the service is normally installed within 10-15 working days. (Id., at 12) Staff selected the higher end of the range provided by the Company to set the deadline.

Finally, Staff noted that the Company recently merged with Ameren and that Ameren had already made it known that it intends to reduce staffing. (Id., at 13) Staff considered the addition of the 15-day limit for installing new services as assurance that any future resource reductions would not cause service deterioration to the Company's customers. (Id.)

The Company, in its rebuttal testimony, provided several reasons why it opposed Staff's recommendation. (CILCO Ex. 4.4, pp. 5-8) Namely the Company's reasons are that:

1) Company not aware of any problem that requires the proposed time limit;

2) Proposed language does not take into account extenuating circumstances beyond the control of the Company;

3) Proposed language does not address how Company is to be made aware of when time limit begins;

4) Proposed language may hamper the Company's ability to efficiently and effectively schedule work that needs accomplished;

5) Proposed language use of the phrase "requested location" may require clarification; and

6) Company concerned if rate case is appropriate venue for this topic. (Staff Ex. 11R at 13)

Staff, in its rebuttal testimony, fully addressed each of the concerns raised by the Company. In particular, Staff noted that it agreed with the Company's statement that there does not currently exist a problem that requires this proposed tariff language change. However, Staff noted the institution of the 15-day new service installation time limit is a proactive step that will help ensure that the Company does not cause service deterioration with its resource reductions. (Id., at 14)

The Company's second concern dealt with the lack of any language to account for extenuating circumstances beyond the control of the Company. Staff addressed this concern by adding language to the proposed tariff revision that allowed the Company to exceed 15 working days if specialized equipment was necessary to install or provide service or if events such as work stoppages, insurrection, acts of terrorism, or other calamities require the Company's resources be directed elsewhere. (Id., at 14-15)

Staff also added language to the proposed tariff change to clarify how the Company would become aware of when the customer location was ready for the installation of the new service in order to address the third concern raised by the Company. In particular, Staff added language to its recommendation that required the party who completed the service application request to contact the Company when the site was ready for the Company to provide service. (Id., at 15)

Staff disputed Company's assertions from its fourth comment, when the Company stated the proposed language may hamper its ability to efficiently and effectively schedule work that needs accomplished. In particular, Staff noted that the Company had indicated that for the period 2000 through 2002, it had fulfilled 95% of the new customer requests within 15 working days. (Id.) Further, the Company was able to meet this standard of service even though the Company's rebuttal testimony provided several examples of reason why the 15-day limit not attainable, such as specialized equipment needs. (Id., at 15-16) Therefore, Staff considered very little, if any, of the Company's existing work practices would require alteration if the Commission accepts Staff's proposed 15-day time limit for new service installations.

Staff did not make any changes to the proposed tariff language based on the Company's fifth comment that the phrase "request location" could require clarification. Staff's intended the phrase as a general reference. The Company indicated that as long as the phrase was just a general reference it did not have any problems with it. (Id., at 16) Therefore, no changes were necessary.

The Company's final concern was whether a rate case is the appropriate venue for considering Staff's proposal to institute a time limit on how long the Company has to install a new service under certain circumstances. Staff disputes the Company's assertion that a rate case may not be the appropriate venue. First, the Company's existing tariff already contains language saying service installations will occur in a reasonable amount of time. Staff's proposal merely clarifies the amount of time the Company is allowed. Second, the Company had ample opportunity to raise any concerns it had regarding the proposal as well as the proposed language selected by Staff in its rebuttal and surrebuttal testimony.

The Company's surrebuttal testimony did not dispute any of the language changes suggested by Staff nor raise any additional concerns about the proposed language. Instead, the Company's testimony simply stated that it did not support any language that would mandate the installation of new services within a specified time limit. (CILCO Ex. 4.8, p. 2) The Company also stated that it strongly believes a proposal, such as this, should be considered in a rule-making proceeding, not a case-by-case basis. (Id., at 3)

Staff's proposal to add tariff language that would require the Company to install new service requests within 15 working days under certain circumstances is in the best interests of the Company's customers. Staff's proposal addressed all of the various concerns raised by the Company about the proposed tariff language, provided specificity to an existing Company tariff about the length of time to install a new service, and is a proactive step in assuring the Company's customers do not see any deterioration in their service quality. Further, the Company's own information indicates that very little, if any, of its work practice would change should the Commission institute this standard. Therefore, the Commission should require the Company to add language to its tariff that would require it to install new services within 15 working days as provided in the below language.

> The Company shall provide service connections to new customers within 15 working days at the requested location after being notified by the party who completed the service application request that property grading is in place, any obstructions or construction materials are removed, the location for the meter installation is prepared, and the Company determines a distribution main extension is not necessary in order to provide service. The 15-day time limit does not apply for those instances where specialized equipment is necessary for or to install the service connection or in the event of work stoppages, insurrection, acts of terrorism, or other calamities that require the Company's resources be directed elsewhere. The Company shall endeavor to provide continuous service to customers attached to the Company's facilities but does not guarantee uninterrupted service and shall not be liable for any damages which the customer may sustain by reason of any failure or interruption of service, increase or decrease in delivery pressure, whether caused by accidents, repairs or other causes except when caused by gross negligence on its part, however, in no event shall the Company be liable for any loss by customer of production, revenues or profits or for any consequential damages whatsoever on account of any failure or interruption of service or increase or decrease in delivery pressure, nor shall the Company be liable for damages that may be incurred by the use of gas equipment or the presence of the Company's property on the customer's premises. (Staff Ex. 11R. pp. 17-18)

2. Maximum Daily Nominagion ("MDN")

Under the Company's current tariff, there is no restriction on the amount of gas that a customer can nominate to the Company's system. In the instant proceeding, the Company proposes an MDN, which would place a limit on the amount of gas that a customer can nominate to the Company's system on any day except for a critical day. Transportation customer deliveries would be limited by the MDN on all days except critical days. The MDN restriction would be waived on critical days. (CILCO Ex. 5.0, pp. 11-13)

The Company originally proposed to calculate a customer's MDN for each month by adding the customer's usage during the same month in the preceding 12 months to the customer's Positive Bank Tolerance and dividing that sum by 30. The Company would provide the customer with an MDN for each month during the year on March 1 of each year. (CILCO Ex. 5.0, pp. 11-13)

Staff witness Iannello identified various deficiencies in the Company's proposed MDN calculation and recommended changes to rectify those potential problems. In order to ensure that a customer will be able to nominate and deliver its entire load to the Company's system without exceeding its MDN, Mr. Iannello recommended that the MDN be calculated in one of the two following ways depending on the type of meter device used to serve the customer. For customers with a meter that does not measure daily use, the MDN would be calculated by adding the customer's non-coincident peak month usage to the customer's positive bank tolerance and dividing this sum by 21. For customers with a meter that records daily usage, the MDN would be calculated by adding the customer's non-coincident peak day demand during the previous calendar year to the quantity of the customer's positive bank tolerance divided by 21. (Staff Ex. 6.0, R-2, pp. 14-15) Mr. Iannello argued that these alternative calculations would place greater restrictions on customer nominations than the Company's current tariff provisions while still providing the customer with the ability to meet its peak demand entirely through deliveries to the Company's system. (Staff Ex. 6.0, R-2, pp. 14-15)

Ms. Seckler adopted Mr. Iannello's recommended calculation of the Maximum Daily Nomination ("MDN") but recommended an alternative calculation of a transportation customer's non-coincident peak day usage. (CILCO Rebuttal Ex. 5.2, p.12) Mr. Iannello accepted Ms. Seckler's alternative non-coincident peak day use calculation. (Staff Ex. 12.0, p. 16)

BEAR witness Lee Smith argues that even Staff's proposed revision to the MDN is not sufficient to allow certain customers, particularly grain dryers, with the ability to nominate a sufficient amount of gas to meet their needs. (BEAR Ex. 2, pp. 9-10) She recommends initially setting the MDN based on Staff witness Iannello's proposed method, but allowing the customer "…to request and receive a modification to the MDN to meet the customers' needs." Staff believes that Ms. Smith's MDN recommendation is too open-ended. Staff, however, agrees that grain dryers have some specific usage characteristics that do not fit Staff's proposed MDN as modified by the Company. In light of the unique usage characteristics of these customers, Staff recommends that CILCO be directed to work with these customers to develop an MDN provision that meets these customers' needs without adversely affecting other customers. (Staff Ex. 6.0 R-2, p. 14)

IIEC witness Mallinkcrodt recommends that the Commission reject the Company's proposed MDN calculation. (IIEC Ex. 1.0, p. 27) Mr. Mallinkcrodt argues that the Company's proposal would severely limit a customer's ability to meet their needs. If the Commission will not reject an MDN requirement altogether, Mr. Mallinkcrodt recommends the same MDN calculation that Staff witness Iannello recommends. While eliminating the MDN provision altogether would remedy the concerns of BEAR witness Smith and provide more flexibility to transportation customers over the use of storage banks, Staff is sympathetic to the Company's concerns regarding the impact of transportation customer activity on the PGA.

VIII. CONCLUSION

For the reasons set forth above, Staff respectfully requests that the Commission approve the proposed Tariffs for the Company, only if Staff's modifications are incorporated.

Respectfully submitted,

____

JANIS E. VON QUALEN
Staff Attorney

Counsel for the Staff of the Illinois
Commerce Commission

Central Illinois Light Company
Statement of Operating Income with Adjustments
For the Test Year Ending December 31, 2001
(In Thousands)

Line No.	Description	Company Rebuttal Pro Forma Present Sched. 7.1, p.2	Staff Adjustments Initial Brief Appendix A Schedule 1.2	Staff Pro Forma Present (Cols. b+c)	Company Proposed Increase Rebuttal Schedule C-1	Staff Gross Revenue Conversion Factor	Proposed Rates With Staff Adjustments (Cols. d+e+f)	Adjustment To Proposed Increase	Staff Pro Forma Proposed (Cols. g+h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Operating Revenues	$ 74,936	$ -	$ 74,936	$ 18,951	$ (59)	$ 93,828	$ (8,844)	$ 84,984
2	Interdept. Sales and Other Revenues	3,024	-	3,024	-	-	3,024	-	3,024
3	PGA Revenues	201,997	-	201,997	-	-	201,997	-	201,997
4	Total Operating Revenue	279,957	-	279,957	18,951	(59)	298,849	(8,844)	290,005
		-							
5	Uncollectible Expense	2,762	(950)	1,812	183	(58)	1,937	(58)	1,879
6	Cost of gas	1,125	-	1,125	-	-	1,125	-	1,125
7	PGA Cost of Gas	201,997	-	201,997	-	-	201,997	-	201,997
8	Other storage expenses	182	-	182	-	-	182	-	182
9	Transmission expenses	1,236	(31)	1,205	-	-	1,205	-	1,205
10	Distribution expenses	11,494	-	11,494	-	-	11,494	-	11,494
11	Customer accounts expenses	6,256	-	6,256	-	-	6,256	-	6,256
12	Customer service and info. expenses	303	-	303	-	-	303	-	303
13	Sales expenses	453	-	453	-	-	453	-	453
14	Administrative and general expenses	19,559	(602)	18,957	-	-	18,957	-	18,957
15	Depreciaton and amortization	22,227	(59)	22,168	-	-	22,168	-	22,168
16	General taxes	2,153	-	2,153	-	-	2,153	-	2,153
17	Total Operating Expense	-							
18	Before Income Taxes	269,747	(1,642)	268,105	183	(58)	268,230	(58)	268,172
		-							
19	State Income Tax	935	144	1,079	1,348	-	2,427	(631)	1,796
20	Federal Income Tax	4,886	575	5,461	6,097	-	11,558	(2,854)	8,704
21	Deferred Taxes and ITCs Net	(4,005)	-	(4,005)	-	-	(4,005)	-	(4,005)
22	Total Operating Expenses	271,563	(923)	270,640	7,628	(58)	278,210	(3,543)	274,667
		-							
23	NET OPERATING INCOME	$ 8,394	$ 923	$ 9,317	$ 11,323	$ (1)	$ 20,639	$ (5,301)	$ 15,338
24	Staff Rate Base (ICC Staff Initial Brief, Appendix A, Schedule 1.3, Column (d))								$ 188,898
25	Staff Overall Rate of Return (ICC Staff Exhibit 9, Schedule 9.1)								8.12%
26	Revenue Change (Col. (i) Line 4 minus Col. (d), Line 4)								$ 10,048
27	Percentage Revenue Change (Col. (i), Line 26 divided by Col. (d), Line 4)								3.59%

Central Illinois Light Company

Statement of Operating Income with Adjustments

For the Test Year Ending December 31, 2001
(In Thousands)

Line No.	Description	Company Pro Forma Present Schedule C-1	Company Rebuttal Adjustments (CILCO Ex. 6.7)	Company Rebuttal Pro Forma Present (B+C)	Company Surrebuttal Adjustments (Note 1)	Company Surrebuttal Pro Forma Present (Col D+E)	Company Initial Brief Adjustments Increase (Source)	Company Initial Brief Pro Forma Present (Col F+G)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Operating Revenues	$ 74,936	$ -	$ 74,936	$ -	$ 74,936	$ -	$ 74,936
2	Interdept. Sales and Other Revenues	3,024	-	3,024	-	3,024	-	3,024
3	PGA Revenues	201,997	-	201,997	-	201,997	-	201,997
4	Total Operating Revenue	279,957	-	279,957	-	279,957	-	279,957
5	Uncollectible Expense	2,762	-	2,762	-	2,762	-	2,762
6	Cost of gas	1,125	-	1,125	-	1,125	-	1,125
7	PGA Cost of Gas	201,997	-	201,997	-	201,997	-	201,997
8	Other storage expenses	182	-	182	-	182	-	182
9	Transmission expenses	1,236	-	1,236	-	1,236	-	1,236
10	Distribution expenses	11,494	-	11,494	-	11,494	-	11,494
11	Customer accounts expenses	6,236	20	6,256	-	6,256	-	6,256
12	Customer service and info. expenses	303	-	303	-	303	-	303
13	Sales expenses	557	(104)	453	-	453	-	453
14	Administrative and general expenses	17,462	2,097	19,559	-	19,559	-	19,559
15	Depreciaton and amortization	22,350	(123)	22,227	-	22,227	-	22,227
16	General taxes	2,161	(8)	2,153	-	2,153	-	2,153
17	Total Operating Expense							
18	Before Income Taxes	267,865	1,882	269,747	-	269,747	-	269,747
19	State Income Tax	1,070	(135)	935	-	935	-	935
20	Federal Income Tax	5,497	(611)	4,886	-	4,886	-	4,886
21	Deferred Taxes and ITCs Net	(4,005)	-	(4,005)	-	(4,005)	-	(4,005)
22	Total Operating Expenses	270,427	1,136	271,563	-	271,563	-	271,563
23	NET OPERATING INCOME	$ 9,530	$ (1,136)	$ 8,394	$ -	$ 8,394	$ -	$ 8,394

Note 1: Not Applicable. The Company did not present a full revenue requirement of its surrebuttal position. Therefore, Staff's Appendix A includes adjustments agreed to by the Company in CILCO Surrebuttal Exhibit 6.9.

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ICC Staff Initial Brief
Appendix A
Schedule 1.2
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Central Illinois Light Company

Adjustments to Operating Income

For the Test Year Ending December 31, 2001
(In Thousands)

Line No.	Description	Interest Synchronization (Appendix A Schedule 1.5)	Depreciation Expense (ICC St. Ex. 7R Sched. 7.7)	Amortization Expense (ICC St. Ex. 7R Sched. 7.8)	Interest On Customer Deposits (ICC St. Ex. 7R Sched. 7.10)	Depreciation Expense (ICC St. Ex. 7R Sched. 7.12)	Rate Case Expense (ICC St. Ex. 8 Sched. 8.1)	Union Payroll Increase (ICC St. Ex. 8 Sched. 8.2)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -		$ -
2	Interdept. Sales and Other Revenues	-	-	-	-	-	-	-	-
3	PGA Revenues	-	-	-	-	-	-	-	-
4	Total Operating Revenue	-	-	-	-	-	-	-	-
5	Uncollectible Expense					-	-		-
6	Cost of gas	-	-	-	-	-	-	-	-
7	PGA Cost of Gas	-	-	-	-	-	-	-	-
8	Other storage expenses	-	-	-	-	-	-	-	-
9	Transmission expenses	-	-	-	-	-	-	-	-
10	Distribution expenses	-	-		-	-	-	-	-
11	Customer accounts expenses	-	-	-	-	-	-	-	-
12	Customer service and info. expenses	-	-	-	-	-	-	-	-
13	Sales expenses	-	-	-	-	-	-	-	-
14	Administrative and general expenses	-	-		-	-	(135)	-	(135)
15	Depreciaton and amortization	-	-	-	-	(59)	-	-	(59)
16	General taxes	-	-	-	-	-	-	-	-
17	Total Operating Expense								
18	Before Income Taxes	-	-	-	-	(59)	(135)	-	(194)
19	State Income Tax	40	-	-	-	4	10	-	54
20	Federal Income Tax	183	-	-	-	19	44	-	246
21	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
22	Total Operating Expenses	223	-	-	-	(36)	(81)	-	106
23	NET OPERATING INCOME	$ (223)	$ -	$ -	$ -	$ 36	$ 81	$ -	$ (106)

Central Illinois Light Company

Adjustments to Operating Income

For the Test Year Ending December 31, 2001

(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Nonrecurring Expense (ICC St. Ex. 8 Sched. 8.3)	Uncollectibles Expense (ICC St. Ex. 8 Sched. 8.4)	Incentive Compensation (ICC St. Ex. 8 Sched. 8.5)	Pensions and Benefits Expense (ICC St. Ex. 8 Sched. 8.6)	Supercompress-ability and Pressure Factors (CILCO Ex. 4.4)	Income Tax Cushion Adjustment (AG/CUB Exhibit 1.0)	Subtotal Operating Statement Adjustments
	(a)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Operating Revenues	$ -	$ -	$ -				$ -	$ -
2	Interdept. Sales and Other Revenues	-	-	-	-	-	-	-	-
3	PGA Revenues	-	-	-	-	-	-	-	-
4	Total Operating Revenue	-	-	-	-	-	-	-	-
5	Uncollectible Expense	-	-	-					-
6	Cost of gas	-	-	-	-	-	-	-	-
7	PGA Cost of Gas	-	-	-	-	-	-	-	-
8	Other storage expenses	-	-	-	-	-	-	-	-
9	Transmission expenses	-	(31)	-	-	-	-	-	(31)
10	Distribution expenses	-	-	-	-	-	-	-	-
11	Customer accounts expenses	-	-	-	-	-	-	-	-
12	Customer service and info. expenses	-	-	-	-	-	-	-	-
13	Sales expenses	-	-	-	-	-	-	-	-
14	Administrative and general expenses	(135)	-		-	(493)	26	-	(602)
15	Depreciaton and amortization	(59)	-	-	-	-	-	-	(59)
16	General Taxes	-	-	-	-	-	-	-	-
17	Total Operating Expense								
18	Before Income Taxes	(194)	(31)	-	-	(493)	26	-	(692)
19	State Income Tax	54	2	-	-	35	(2)	(13)	76
20	Federal Income Tax	246	10	-	-	160	(8)	(142)	266
21	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
22	Total Operating Expenses	106	(19)	-	-	(298)	16	(155)	(350)
23	NET OPERATING INCOME	$ (106)	$ 19	$ -	$ -	$ 298	$ (16)	$ 155	$ 350

Central Illinois Light Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2001
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Uncollectibles Expense (AG/CUB Exhibit 1.1)	(Source)	(Source)	(Source)	(Source)	(Source)	Total Operating Statement Adjustments
	(a)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
1	Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Interdept. Sales and Other Revenues	-	-	-	-	-	-	-	-
3	PGA Revenues	-	-	-	-	-	-	-	-
4	Total Operating Revenue	-	-	-	-	-	-	-	-
5	Uncollectible Expense	-	(950)						(950)
6	Cost of gas	-	-	-	-	-	-	-	-
7	PGA Cost of Gas	-	-	-	-	-	-	-	-
8	Other storage expenses	-	-	-	-	-	-	-	-
9	Transmission expenses	(31)	-	-	-	-	-	-	(31)
10	Distribution expenses	-	-	-	-	-	-	-	-
11	Customer accounts expenses	-	-	-	-	-	-	-	-
12	Customer service and info. expenses	-	-	-	-	-	-	-	-
13	Sales expenses	-	-	-	-	-	-	-	-
14	Administrative and general expenses	(602)	-	-	-	-	-	-	(602)
15	Depreciaton and amortization	(59)	-	-	-	-	-	-	(59)
16	General Taxes	-	-	-	-	-	-	-	-
17	Total Operating Expense								
18	Before Income Taxes	(692)	(950)	-	-	-	-	-	(1,642)
19	State Income Tax	76	68	-	-	-	-	-	144
20	Federal Income Tax	266	309	-	-	-	-	-	575
21	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
22	Total Operating Expenses	(350)	(573)	-	-	-	-	-	(923)
23	NET OPERATING INCOME	$ 350	$ 573	$ -	$ -	$ -	$ -	$ -	$ 923

Central Illinois Light Company
Rate Base
For the Test Year Ending December 31, 2001
(In Thousands)

Line No.	Description	Company Rebuttal Pro Forma Rate Base Sched. 7.3, p. 2	Staff Adjustments Initial Brief (Appendix A Sched. 1.4)	Staff Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross utility plant in service	$ 469,940	(14,534)	$ 455,406
2	Less accum. deprec. and amort.	(262,783)	2,779	(260,004)
3	CWIP without AFUDC	6,899	-	6,899
4	Net Plant	214,056	(11,755)	202,301
5	Additions to Rate Base			
6	Working capital allowance	25,041	(3,602)	21,439
7	Budget plan balances	545	-	545
8	Cash Working Capital		-	-
9			-	-
10			-	-
11			-	-
12			-	-
13	-	-	-	-
14	-	-	-	-
15	-	-	-	-
16	Deductions From Rate Base			
17	Accum. deferred income taxes	(26,272)	-	(26,272)
18	Customer advances for construction	(1,996)	-	(1,996)
19	Customer deposits	(1,317)	-	(1,317)
20	Pre-1971 ITC's	(22)	-	(22)
21	Unfunded pension costs	(5,780)	-	(5,780)
22		-	-	-
23	Rate Base	$ 204,255	$ (15,357)	$ 188,898

Central Illinois Light Company
Rate Base
For the Test Year Ending December 31, 2001
(In Thousands)

Line No.	Description	Company Direct Pro Forma (Schedule B-1)	Company Rebuttal Adjustments (CILCO Ex. 6.6)	Company Rebuttal Pro Forma (B+C)	Company Surrebuttal Adjustments (Note 1)	Company Surrebuttal Pro Forma Present (Col D+E)	Company Initial Brief Adjustments (Source)	Company Initial Brief Pro Forma Present (Col F+G)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Gross utility plant in service	$ 471,025	$ (1,085)	$469,940	$ -	$469,940	$ -	$469,940
2	Less accum. deprec. and amort.	(263,100)	317	(262,783)	-	(262,783)	-	(262,783)
3	CWIP without AFUDC	6,899	-	6,899	-	6,899	-	6,899
4	Net Plant	214,824	(768)	$214,056	-	$214,056	-	$214,056
5	Additions to Rate Base		-	-	-	-	-	-
6	Working capital allowance	24,824	217	25,041	-	25,041	-	25,041
7	Budget plan balances	561	(16)	545	-	545	-	545
8	Cash Working Capital	-		-	-	-	-	-
9			-	-	-	-	-	-
10			-	-	-	-	-	-
11			-	-	-	-	-	-
12			-	-	-	-	-	-
13	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-
16	Deductions From Rate Base		-	-	-	-	-	-
17	Accum. deferred income taxes	(28,038)	1,766	(26,272)	-	(26,272)	-	(26,272)
18	Customer advances for construction	(1,996)		(1,996)	-	(1,996)	-	(1,996)
19	Customer deposits	(1,504)	187	(1,317)	-	(1,317)	-	(1,317)
20	Pre-1971 ITC's	(22)	-	(22)	-	(22)	-	(22)
21	Unfunded pension costs	(5,780)	-	(5,780)	-	(5,780)	-	(5,780)
22		-	-	-	-	-	-	-
23	Rate Base	$ 202,869	$ 1,386	$ 204,255	$ -	$ 204,255	$ -	$ 204,255

Note 1: Not Applicable. The Company did not present a full revenue requirement of its surrebuttal position. Therefore, Staff's Appendix A includes adjustments agreed to by the Company in CILCO Surrebuttal Exhibit 6.9.

Docket No. 02-0837
ICC Staff Initial Brief
Appendix A
Schedule 1.4

Central Illinois Light Company
Adjustments to Rate Base
For the Test Year Ending December 31, 2001
(In Thousands)

Line No.	Description	YTD Sept. Gas Plant Additions ICC St. Ex. 7R Sched. 7.7	AM/FM Gas Mapping Pro Forma ICC St. Ex. 7R Sched. 7.8	Materials & Supplies Inv. ICC St. Ex. 7R Sched. 7.9	Customer Deposits ICC St. Ex. 7R Sched. 7.10	Budget Payment Plan Balances ICC St. Ex. 7R Sched. 7.11	IDOT Reimbursement ICC St. Ex. 7R Sched. 7.12	Capitalized Pensions and Benefits ICC St. Ex. 8 Sched. 8.7	Subtotal Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross utility plant in service	$ -	$ -		$ -	$ -	$ (2,036)	$ (159)	$ (2,195)
2	Less accum. deprec. and amort.	-	-	-	-	-	2,036	-	2,036
3	CWIP without AFUDC	-	-	-	-	-	-	-	-
4	Net Plant	-	-	-	-	-	-	(159)	(159)
	-								
5	Additions to Rate Base								
6	Working capital allowance	-	-	(143)	-	-	-	-	(143)
7	Budget plan balances	-	-	-	-		-	-	-
8	Cash Working Capital	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-
16	Deductions From Rate Base	-	-	-	-	-	-	-	-
17	Accum. deferred income taxes	-	-	-	-	-	-	-	-
18	Customer advances for construction	-	-	-	-	-	-	-	-
19	Customer deposits	-	-	-	-	-	-	-	-
20	Pre-1971 ITC's	-	-	-	-	-	-	-	-
21	Unfunded pension costs	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-
23	Rate Base	$ -	$ -	$ (143)	$ -	$ -	$ -	$ (159)	$ (302)

Central Illinois Light Company

Adjustments to Rate Base

For the Test Year Ending December 31, 2001
(In Thousands)

Line No.	Description	Subtotal Rate Base Adjustments	Gas Stored Underground ICC St. Ex. 11R Sched. 11.1	Post-2001 Pro Forma Plant Additions Appendix A Sched. 1.7	(Source)	(Source)	(Source)	(Source)	Total Rate Base Adjustments
	(a)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Gross utility plant in service	$ (2,195)	$ -	$ (12,339)	$ -	$ -	$ -	$ -	$ (14,534)
2	Less accum. deprec. and amort.	2,036	-	743	-	-	-	-	2,779
3	CWIP without AFUDC	-	-	-	-	-	-	-	-
4	Net Plant	(159)	-	(11,596)	-	-	-	-	(11,755)
	-								
5	Additions to Rate Base								-
6	Working capital allowance	(143)	(3,459)	-	-	-	-	-	(3,602)
7	Budget plan balances	-	-	-	-	-	-	-	-
8	Cash Working Capital	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-
16	Deductions From Rate Base								
17	Accum. deferred income taxes	-	-	-	-	-	-	-	-
18	Customer advances for construction	-	-	-	-	-	-	-	-
19	Customer deposits	-	-	-	-	-	-	-	-
20	Pre-1971 ITC's	-	-	-	-	-	-	-	-
21	Unfunded pension costs	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-
23	Rate Base	$ (302)	$ (3,459)	$ (11,596)	$ -	$ -	$ -	$ -	$ (15,357)

Central Illinois Light Company
Interest Synchronization Adjustment
For the Test Year Ending December 31, 2001
(In Thousands)

Line No.	Description	Amount	
	(a)	(b)	
1	Rate Base Per Staff	$ 188,898	(1)
2	Weighted Cost of Debt	2.73%	(2)
3	Synchronized Interest Per Staff	5,157	
4	Company Interest Expense	5,719	(3)
5	Increase (Decrease) in Interest Expense	(562)	
6	Increase (Decrease) in State Income Tax Expense		
7	at 7.180%	$ 40	
8	Increase (Decrease) in Federal Income Tax Expense		
9	at 35.000%	$ 183	

(1) Source: ICC Staff Initial Brief, Schedule 1.3, Page 1 of 2, Column (d).
(2) Source: ICC Staff Exhibit 9, Schedule 9.1.
(3) Source: Company Schedule C-3.1.

Central Illinois Light Company
Gross Revenue Conversion Factor
For the Test Year Ending December 31, 2001
(In Thousands)

Line No.	Description		Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(a)		(b)	(c)	(d)
1	Revenues			1.000000	
2	Uncollectibles	(1)	0.6600%	0.006600	
3	State Taxable Income			0.993400	1.000000
4	State Income Tax		7.1800%	0.071326	0.071800
5	Federal Taxable Income			0.922074	0.928200
6	Federal Income Tax		35.0000%	0.322726	0.324870
7	Operating Income			0.599348	0.603330
8	Gross Revenue Conversion Factor Per Staff			1.668480	1.657468

(1) Source: AG/CUB Exhibit 1.1, Tr. pp. 46-47.

Central Illinois Light Company
Adjustment to Post-2001 Pro Forma Plant Additions - Plant in Service
For the Test Year Ended December 31, 2001
(Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
	Rate Base Adjustment:	Dr / (Cr)	
1	Total Post-2001 Pro Forma Plant Additions	$ (14,139)	(1)
2	YTD Sept. 2002 Duplicate Gas Plant Additions	1,800	(2)
3	Staff Proposed Adjustment - Plant in Service	$ (12,339)	(3)

(1) Source: CILCO Schedule B-1, B-2.1. *

(2) Source: ICC Staff Exhibit 1, Schedule 1.7.

(3) Source: Line 1 less line 2. Staff's incorporation of AG/CUB witness Effron's proposal to eliminate all post-2001 pro forma plant additions.

* See reconciliation to CILCO Revised Schedule B-2.1 below:

Line No.	Description	Amount
4	Source: CILCO Revised Schedule B-2.1 (CILCO Rebuttal Exhibit 6.2)	$ 12,347
5	Source: CILCO Rebuttal Exhibit 6.6, Page 1 of 2, column (e)	(8)
	Source: Line 4 less line 5, remaining post-2001 pro forma plant additions.	$ 12,339

Central Illinois Light Company
Adjustment to Post-2001 Pro Forma Plant Additions - Accumulated Depreciation
For the Test Year Ended December 31, 2001
(Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
	Rate Base Adjustment:	Dr / (Cr)	
1	Accumulated Depreciation - Total Post-2001 Pro Forma Plant Additions	$ 821	(1)
2	Accumulated Depreciation - YTD Sept. 2002 Duplicate Gas Plant Additions	78	(2)
3	Staff Proposed Adjustment - Accumulated Depreciation Pro Forma Plant Additions	$ 743	(3)

(1) Source: CILCO Schedule B-1, B-3.1.
(2) Source: ICC Staff Exhibit 1, Schedule 1.7, Page 3 of 6, line 3, column (b).
(3) Source: Line 1 less line 2. Staff's incorporation of AG/CUB witness Effron's proposal to eliminate all post-2001 pro forma plant additions and related accumulated depreciation.

Appendix B

Staff Rebuttal Proposal

Capital Structure Component	Balance	Percent of Total Capitalization	Cost	Weighted-Average Cost of Capital
Long-Term Debt	$314,706,894	45.69%	5.98%	2.73%
Preferred Stock	39,735,976	5.77%	5.43%	0.31%
Common Equity	334,284,000	48.54%	10.47%	5.08%
Total	$688,726,870[1]	100.00%		**8.12%**

[1] Staff Exhibit 9.0, Schedule 9.1 and Staff Exhibit 3.0, Schedule 3.1 contain a typographical error. Staff Exhibit 9.0, Schedule 9.1 and Staff Exhibit 3.0, Schedule 3.1 present CILCO's total capitalization as $688,903,180. In reality, CILCO's capitalization totals $688,726,870.