STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

AMEREN ILLINOIS COMPANY d/b/a Ameren Illinois, Petitioner	))))	Docket No. 15-0142
Proposed general increase in gas delivery service rates and revisions to other terms and conditions of service.	)))	

INITIAL BRIEF OF THE STAFF
OF THE ILLINOIS COMMERCE COMMISSION

JIM OLIVERO
KELLY A. TURNER
MARCY SHERRILL

Illinois Commerce Commission
Office of General Counsel
160 North LaSalle Street, C-800
Chicago, IL 60601
(312) 793-2877
jolivero@icc.illinois.gov
kturner@icc.illinois.gov
msherrill@icc.illinois.gov

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Counsel for Staff of the Illinois Commerce Commission

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NOW COME the Staff witnesses of the Illinois Commerce Commission ("Staff"), by and through their undersigned counsel, pursuant to Section 200.800 of the Illinois Commerce Commission's Rules of Practice (83 Ill. Adm. Code 200.800), and the direction of the Administrative Law Judge ("ALJ"), respectfully submit their Initial Brief ("Staff IB") in the above-captioned matter.

I. INTRODUCTION

Ameren Illinois Company ("Ameren," "AIC," or the "Company") filed new tariff sheets on January 23, 2015 in which the Company proposed general increases in its natural gas rates. On February 6, 2015, the presiding Administrative Law Judges ("ALJs") issued a Notice of Deficiencies to Ameren; Ameren filed corrections to those deficiencies on March 6, 2015. On February 23, 2015 the Company's tariff sheets were suspended by the Commission and, on June 3, 2015, the Commission entered a Re-suspension Order extending the suspension to and including December 21, 2015. On April 7, 2015, the ALJs issued an order establishing a Case Management Plan which detailed a schedule for submission of pre-filed testimony, hearings and post-hearing briefs.

In response to the Company's filing, the following parties filed Petitions to Intervene, all of which were granted: Citizen Utility Board ("CUB"); the Retail Energy Supply Association ("RESA"); Archer-Daniels Midland as one of Illinois Industrial Energy Consumers ("IIEC"); Illinois Competitive Energy Association ("ICEA"). The People of the State of Illinois *ex rel.* Lisa Madigan, Attorney General of the State of Illinois ("AG") filed an appearance and participated in the case as a party of right.

The following witnesses submitted testimony on behalf of Staff: Scott Tolsdorf (Staff Exhibit ("Ex.") 1.0 and Staff Ex. 7.0); Theresa Ebrey (Staff Ex. 2.0 and Staff Ex. 8.0); Sheena Kight-Garlisch (Staff Ex. 3.0 and 9.0); Alicia Allen (Staff Ex. 4.0 and Staff Ex. 10.0), Eric Lounsberry (Staff Ex. 5.0 and Staff Ex. 11.0), Michael McNally (Staff Ex. 6.0 and Staff Ex. 12.0), and David Reardon (Staff Ex. 13.0).

During the course of the proceeding, Staff proposed various adjustments and changes to the Company's January 23, 2015 filing. Ameren accepted certain of Staff's modifications, Staff withdrew others and some were resolved through discussions and discovery. Appendices A through C attached hereto include the Revenue Requirement Schedules proposed by Staff for the gas rate zones, Rate Zone 1, Rate Zone 2, and Rate Zone 3, respectively. For the reasons stated below, Staff's proposed adjustments should be adopted by the Commission. In instances where Staff does not address an issue in this brief, Staff makes no recommendation on that issue.

II. RATE BASE

A. Resolved/Uncontested Issues

1. Working Capital for Gas in Storage

Staff and the Company agreed on the valuation of Ameren's working capital allowance for gas in storage after making several changes to Ameren's initial request. In its direct testimony, Staff noted that Ameren's original request relied on dated natural gas pricing expectations for its 2016 test year. Due to the reliance on dated pricing, Staff recommended that Ameren update its request by relying on the more current New York Mercantile Exchange strip price for 2016 gas prices, as well as accounting for all known hedging positions Ameren had taken for gas it planned to purchase in 2016. (Staff Ex. 5.0, 18.) In its rebuttal filing, Ameren responded by proposing to value its working capital allowance for gas in storage on the U.S. Energy Information Administration's ("EIA") Short-Term Energy Outlook ("STEO") for all gas not already purchased via Ameren's hedging program for 2016. (Ameren Ex. 30.0, 7-8.) In its rebuttal filing, Staff agreed to Ameren's revised gas pricing methodology, but requested Ameren update its pricing to rely on the July 2015 EIA's STEO. (Staff Ex. 11.0, 11.) Ameren agreed to Staff's recommendation in its surrebuttal filing. (Ameren Ex. 35.0, 2.) The parties' agreement regarding working capital allowance for gas in storage results in the following amounts for each Rate Zone ("RZ"): RZ 1 - $12,957,000; RZ 2 - $20,468,000; and RZ 3 - 33,207,000. (Staff Ex. 11.0, Schedule 11.03.)

2. Gas Vehicle Plant Additions

In its direct filing, Staff noted that Ameren's actual vehicle purchases for 2015 were fewer than its projections. Staff expressed concern that the variance between actual and projected purchases could have caused Ameren to overstate its estimated vehicle purchases for 2015 and 2016. (Staff Ex. 5.0, 21.) In its rebuttal filing, Ameren responded by noting the implementation of new truck specification/designs for its 2015 purchases had required the manufacturer to change cost quotes which pushed some purchases into the later part of 2015, but that Ameren had issued purchase orders for the majority of its expected expenditures in 2015. (Ameren Ex. 22.0 (2d Rev.), 8-10.) In its rebuttal filing, Staff noted that Ameren provided further updates on its 2015 vehicle purchases via a data request response that indicated Ameren had purchase orders in place for the vast majority of its 2015 expected vehicle expenditures and that the remaining cost projection would go toward indirect overhead costs. (Staff Ex. 11.0, 15.) As a result, Staff stated that it had no remaining concerns with Ameren's proposed 2015 and 2016 vehicle purchases. (Id.)

3. Customer Advances

4. Qualifying Infrastructure Plant (QIP Additions)

5. Asset Retirement Obligations

Staff proposed to remove electric Asset Retirement Obligations ("AROs") allocated to Ameren's gas utility and included in Ameren's gas rate base. (Staff Ex. 1.0, 6-7:127-147.) The Company agreed with this adjustment in theory and proposed corrections to Staff's adjustment to reflect some additional derivative impacts due to the removal of the AROs. (Ameren Ex. 17.0, 4: 66-77.) Staff agreed with the derivative adjustments as calculated by the Company. (Staff Ex. 7.0, 3:50-57.) This issue is uncontested.

6. Original Cost Determinations

In rebuttal testimony, Staff recommended the removal of AROs be taken into account in the calculation of the original cost determination. (Staff Ex. 7.0, 12:257-264.)

As explained in the Company's surrebuttal testimony, however, the AROs were not included in the Company's calculation of the original cost for gas plant. (Ameren Ex. 34.0, 4-5:82-107.) Upon further review, Staff agrees with the Company. Staff recommends the Commission approve the Company's request for an original cost determination by including the following language in its Findings and Ordering paragraphs of its Order:

(x1) the Commission, based on Ameren's gas Rate Zone I original cost of plant in service as of December 31, 2013, before adjustments, of $451,217,000, and reflecting the Commission's determination adjusting that figure, approves $448,080,000 as the original cost of plant for Ameren's gas Rate Zone I as of said date;

(x2) the Commission, based on Ameren's gas Rate Zone II original cost of plant in service as of December 31, 2013, before adjustments, of $628,131,000, and reflecting the Commission's determination adjusting that figure, approves $623,745,000 as the original cost of plant for Ameren's gas Rate Zone II as of said date; and

(x3) the Commission, based on Ameren's gas Rate Zone III original cost of plant in service as of December 31, 2013, before adjustments, of $1,108,946,000, and reflecting the Commission's determination adjusting that figure, approves $1,101,146,000 as the original cost of plant for Ameren's gas Rate Zone III as of said date.

No other party addressed this issue in testimony and Staff considers it to be uncontested.

7. Hillsboro Used and Useful

In its direct filing, Ameren noted that it did not believe it was appropriate to reduce Ameren's plant in service because of the Commission's historical used and useful adjustment of Ameren's Hillsboro storage field. (Ameren Ex. 7.0 (4d Rev.), 20-21.) In particular, Ameren noted that the more recent historical cycling data showed the Hillsboro storage field was operating at a 100% used and useful manner. (Id. at 21.) In its direct filing, Staff agreed with Ameren that the Commission should find the Hillsboro storage field to be 100% used and useful. (Staff Ex. 5.0, 15.)

B. Contested issues

1. Accounts Payable for Gas Stored Underground

2. Non-Union Salaries and Wages (see III.B.2)

3. Incentive Compensation Costs (see III.B.3)

4. Qualified Pension and Other Post-Employment Benefit Costs (see III.B.4)

5. Non-Qualified Pension Costs (see III.B.5)

6. Gasoline and Diesel Fuel Costs (see III.B.6)

In its direct filing, Staff expressed concern that Ameren used dated prices for its estimate of 2016 gasoline and diesel fuel costs in its initial filing. (Staff Ex. 5.0, 4-9.) As a result, Staff recommended that Ameren rely on the gasoline and diesel fuel prices from the April 2015 EIA STEO, after accounting for variances between the historical EIA fuel prices and Ameren's actual historical fuel prices. (Id. at 5-9.) Staff also recommended that Ameren amend its requested rates to account for lower fuel costs for any fuel costs that it had capitalized. (Id. at 20.) In its rebuttal filing, Ameren agreed to amend its requested rates to account for the more recent fuel prices in a manner consistent with Staff's proposal. (Ameren Ex. 18.0 (Rev.), 3.) In its rebuttal filing, Staff recommended a further reduction to Ameren's requested rates to account for gasoline and diesel fuel cost based on the July 2015 EIA STEO. Staff noted the effect of its adjustment was a reduction of $4,000 for RZ 1, $6,000 for RZ 2, and $10,000 for RZ 3. (Staff Ex. 11.0, 13-14.) In its surrebuttal filing, Ameren agreed to Staff's recommendation. (Ameren Ex. 35.0, 2.)

As noted above, Staff and Ameren are in agreement on this issue. However, the AG recommends that Ameren utilize its actual gasoline and diesel fuel costs from the first four months of 2015 as the basis for its assumed 2016 prices. (AG Ex. 5.0, 17.) Staff disagrees with the AG's request. In particular, Staff notes that its recommendation relies on gasoline and diesel fuel price projections from the EIA, a Federal entity that collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. (Staff Ex. 5.0, 5.) The AG's proposal simply relies on a snap shot of prices at a set point in time that may or may not bear any resemblance to Ameren's actual 2016 gasoline and diesel fuel prices. Consequently, Staff recommends that the Commission reject the AG's methodology and its proposed adjustment.

7. Gas-Only Employee Headcount/Vacancy Costs (see III.B.7)

In its direct filing, Staff expressed concern about Ameren's ability to increase its gas-only headcount in the timeframe and manner proposed by the Company. In particular, Staff noted that, through the end of April 2015, Ameren had projected an increase in headcount of 31 gas-only employees, but only achieved an increase of 11 gas-only employees, a variance of 20 employees. (Staff Ex. 5.0, 10.) Staff also noted that if Ameren's hiring trend continued, then Ameren should revise its expected gas-only headcount for the 2016 test year. (Id. at 11.)

In its rebuttal testimony, Ameren indicated that it had made significant progress in hiring gas-only employees in May and June of 2015. In particular, Ameren noted that at the end of June it only had a variance between projected and actual gas-only positions of nine positions rather than the 20 previously identified by Staff. In addition, Ameren had hired five employees who were expected to start after the end of July 2015, so the variance would be further reduced. (Ameren Ex. 22.0, (2d Rev.), 4.) Ameren also noted that several things factor into the variance, including the amount of attrition, the type of positions Ameren is seeking to fill, and the need to develop a new hiring process for gas apprentices. (Id. at 5.)

Staff's rebuttal filing noted that Ameren had provided Staff with more up-to-date information regarding its gas-only headcount. Specifically, Ameren provided information to Staff that indicated it had reduced its projected gas-only employee levels by two people for both 2015 and 2016. (Staff Ex. 11.0, 9.) Further, while Ameren still showed a variance of 14 positions between it's projected versus actual gas-only employee levels at the end of July 2015, Ameren had company-wide commitments in place to hire 11 additional employees in 2015, and was attempting to fill several other positions that could result in additional gas-only hiring in 2015. (Id.) Staff stated it no longer had any concerns with Ameren's assumed levels of gas-only employees. (Id.)

C. Recommended Rate Base

Based on the rate bases for the gas utilities originally proposed by AIC for each of its rate zones and Staff's proposed adjustments to those rate bases as summarized above, the gas utility rate base proposed by Staff for rate zone 1 is $277,341,000, for rate zone 2 is $285,303,000, and for rate zone 3 is $622,595,000. The rate bases are summarized as follows:

Staff Recommended Rate Bases

(In Thousands)

Description	Rate Zone 1 (CIPS)	Rate Zone 2 (CILCO)	Rate Zone 3 (IP)
Gross Plant in Service	$548,413	$746,543	$1,309,437
Accumulated Depreciation	(230,613)	(405,020)	(580,959)
Net Plant	317,800	341,523	728,478
Additions to Rate Base			
Cash Working Capital	6,211	6,223	12,563
Materials & Supplies Inventory	14,919	22,777	37,034
Deductions From Rate Base			
Accumulated Deferred Income Taxes	(56,508)	(77,739)	(143,381)
Customer Advances	(2,584)	(3,556)	(6,558)
Customer Deposits	(2,497)	(3,925)	(5,541)
Rate Base	$277,341	$285,303	$622,595

III. Operating Revenues and Expenses

A. Resolved/Uncontested Issues

1. Ameren Services Company (AMS) Test Year Charges (see also IX.A.1)

2. Transmission Lines Assessment and Inspection Expense

3. Rate Case Expense

Based on the language in the Stipulation filed on July 29, 2015, AIC, IIEC, CUB and Staff agreed that rate case expense for this proceeding should be reduced by $242,366. (Ameren Ex. 32.1, 3-4.)

As a result of the agreed upon reduction in rate case expense set forth in the Stipulation, Staff proposed that the Order in this proceeding express a Commission conclusion as follows:

> The Commission has considered the costs expended by the Company to compensate attorneys and technical experts to prepare and litigate this rate case proceeding and assesses that such costs in the total amount of $2,392,000, which is $1,196,000 amortized over 2 years, or $399,000 per rate zone for the test year, are just and reasonable pursuant to Section 9-229 of the Act (220 ILCS 5/9-229).
> (Staff Ex. 8.0, 4:66-76.)

The Company did not take issue with this recommended language. (Ameren Ex. 34.0, 4:77-78.)

In his direct testimony, Staff witness McNally proposed that Mr. Fetter's consulting fees be disallowed from recovery through rates. He testified that Mr. Fetter's testimony is duplicative of that provided by other AIC witnesses. He observed that Mr. Fetter does not present any analysis or an independent estimate of Ameren's cost of capital; rather, for the essentials on Ameren's cost of capital, Mr. Fetter directed the reader to the testimony of AIC witness Hevert. In fact, Mr. McNally testified that when Mr. Fetter was specifically asked to provide any studies or analysis underlying his positions, he declined ten times. Mr. McNally further noted that Mr. Fetter's work relates entirely to credit ratings and regulatory environment, but Mr. Nelson, Mr. Martin, and Mr. Hevert already address those issues. (Staff Ex. 6.0, 7-8.)

The issue Mr. McNally raised concerning Mr. Fetter's fees was resolved as a part of the Stipulation between AIC, IIEC, CUB, and Staff regarding Ameren's cost of capital and other issues. (Ameren Exhibit 32.1, 3.) Therefore, Mr. McNally did not respond to Mr. Fetter's rebuttal testimony and withdrew his proposed adjustment to Mr. Fetter's fees. Mr. McNally noted that his silence regarding Mr. Fetter's rate case expenses in his rebuttal testimony should not be construed to mean that he agrees to the positions taken by Mr.

Fetter or that he believes Mr. Fetter's testimony provides value in advancing the process of rate setting. (Staff Ex. 12.0, 1.)

4. Payroll Taxes

Staff proposed an adjustment to remove payroll taxes associated with incentive compensation because the Company removed incentive compensation from the revenue requirement. (Staff Ex. 2.0, 4:79–80.) Ameren agreed in part to Staff's adjustment, refining the calculation to allow for the Social Security rate cap. (Ameren Ex. 17.0, 8:163-170, 9:171–181.) Staff accepted Ameren's revised adjustment amount. (Staff Ex 8.0, 2:30-32.)

5. Lobbying Expense

Staff proposed an adjustment to remove the cost of four employees attributed to lobbying. (Staff Ex. 2.0, 3:57-59.) Ameren accepted Staff's adjustment. (Ameren Ex. 17.0, 5:97-108.)

6. Uncollectible Expense/Gross Revenue Conversion Factors

Staff proposed an adjustment to Uncollectibles Expense based on a percentage derived from a three-year average of net write-offs of accounts receivable. (Staff Ex. 2.0, 5:91-94.) Ameren accepted Staff's adjustment and methodology for reflecting Uncollectibles Expense in the revenue requirement. (Ameren Ex. 17.0, 5:91–96.)

7. Rental Revenues

8. Asset Retirement Obligations (see II.A.5)

Staff proposed to remove electric AROs allocated to Ameren's gas utility and included in Ameren's gas rate base. (Staff Ex. 1.0, 6-7:127-147.) The Company agreed with this adjustment in theory and proposed corrections to Staff's adjustment to reflect some additional derivative impacts due to the removal of the AROs. (Ameren Ex. 17.0, 4: 66-77.) Staff agreed with the derivative adjustments as calculated by the Company. (Staff Ex. 7.0, 3:50-57.) This issue is uncontested.

B. Contested Issues

1. Charitable Contributions

Staff proposed to reduce the overall level of the Company's forecasted contributions to a 3-year average of actual contributions (2012-2014) with a 2% increase for 2015 and 2016. (Staff Ex. 7.0, 5-6:106-110.) This is the same methodology that was accepted by the Commission in Ameren's most recent gas rate case. *Ameren Illinois Company d/b/a Ameren Illinois*, Proposed general increase in gas rates, ICC Final Order Docket No. 13-0192, 209 (Dec. 18, 2013) ("2013 Gas Rate Final Order"). In direct and rebuttal testimonies, the Company has asked for a 102% increase over what the Company is currently collecting in rates. (Staff Ex. 7.0, 8-9:176-179.) In surrebuttal testimony, the Company increased this amount, requesting an additional $1,000,000 ($398,000 allocable to gas) which, if allowed by the Commission, would result in a 228%[1] increase over what customers are currently paying in rates for a discretionary expense. The Company's contention that this 228% increase is reasonable is dubious, especially in light of their past practices.

The Public Utilities Act ("Act") allows for the recovery of a reasonable amount of charitable contributions. 220 ILCS 5/9-227. Charitable contributions are a discretionary

[1] Requested 2016 contributions $641,000 (Ameren Schedule C-2.14) plus additional $398,000 (Ameren Ex. 33.0, 2:23) = $1,039,000. $1,039,000 - $317,000 (amount currently recovered in rates) = $722,000. $722,000/ $317,000 = 228%.

expense that a utility can choose unilaterally to incur or to not incur as a utility sees fit. In recent years, Ameren has exercised their discretion to make charitable donations at a level far below what the Company has collected in rates. For example, in a prior gas rate case, the Company proposed a 2012 future test year with an estimate of $2,000,000 in charitable contributions, of which $775,000 would be allocated to gas (*Ameren Illinois Company d/b/a Ameren Illinois*, Proposed general increase in natural gas rates, ICC Final Oder, Docket 11-0282, 26 (January 10, 2012) ("Final Order 11-0282").) In 2012, however, the Company made only $366,575 in contributions allocated to gas. This was less than half of what the Company budgeted for charitable contributions that year. Further, during the 3-year period from 2011-2013, the Company collected $1,370,000 for charitable contributions through rates but during that same time period only made donations of $916,081. (Staff Ex. 7.0, Attachment A.) It appears that when money is tight, the Company has chosen to spend its discretionary charitable contribution dollars on other things.[2] The Commission has expressed concern about this very practice:

> First, the Commission notes that by its own admission AIC reduced its charitable contributions in the past when its financial resources were constrained. AIC now apparently foresees a sufficiently improved financial situation to significantly increase discretionary donations (and gain the associated goodwill and positive publicity) with the expectation that ratepayers will provide the entire amount of the donations. The Commission is concerned that AIC's proposal would seem to reverse its decision to decrease charitable contributions when the full cost could not be effectively passed along to its ratepayers. For AIC to now expect others, some who may be in financial distress, to fund

[2] It is worth noting that the Public Utilities Act includes no provision under which a utility can be made to reconcile actual charitable giving with the amount collected for charitable giving through rates. Once rates are set, the utility alone has the discretion to donate, or not donate, to charity. Should the utility donate less than what is collected, the overage is "profit" to the Company.

> its donations in the name of charity is troubling to the Commission.

(Id. at 31.)

The Commission-approved methodology used by Staff in developing its recommendation does not prevent the Company from making donations to the charitable organizations of its choice. Further, it does not prevent the Company from recouping charitable donations through rates at a level that reflects the level of giving at which the Company was actually engaged. Use of the most recent 3-year average with an inflation factor rewards the Company for the actual donations the Company has made in the past, while anticipating the Company will maintain or grow their level of charitable giving in future years. Historically, Ameren has filed for a rate increase every two to three years and there is no reason to believe that this trend will not continue. If the Commission adopts the same methodology that was applied in the last Ameren gas rate case, the Company will continue to recoup through rates amounts commensurate with the actual contributions the Company has made. The very purpose of establishing rates utilizing a test year is so that expenses are normalized and future years do not reflect aberrations in the utility's operations. A 228% increase in charitable giving is an aberration, as it bears no relation to the Company's past practices. If and when the Company makes actual donations which are 228% greater than what is currently being collected in rates, then future rate years will be adjusted to reflect that level of contributions. Until then, the Company's actual charitable giving should be the bench mark by which the Commission sets a reasonable level of contributions to be collected from ratepayers.

2. Non-Union Salaries and Wages

3. Incentive Compensation Costs

4. Qualified Pension and Other Post-Employment Benefit Costs

5. Non-Qualified Pension Costs

6. Gasoline and Diesel Fuel Costs

In its direct filing, Staff expressed concern that Ameren used dated prices for its estimate of 2016 gasoline and diesel fuel costs in its initial filing. (Staff Ex. 5.0, pp. 4-9.) As a result, Staff recommended that Ameren rely on the gasoline and diesel fuel prices from the April 2015 EIA STEO, after accounting for variances between the historical EIA fuel prices and Ameren historical fuel prices. (Id. at 5-9.) In its rebuttal filing, Ameren agreed to amend its requested O&M expenses to account for the more recent fuel prices. (Ameren Ex. 18.0 (Rev.), 3.) In its rebuttal filing, Staff recommended a further reduction to Ameren's requested O&M expenses to account for gasoline and diesel fuel cost based on the July 2015 EIA STEO. Staff noted the effect of its adjustment was a reduction of in gasoline expenses of $7,549 for RZ 1, $8,088 for RZ 2, and $15,754 for RZ 3 as well as a reduction in diesel fuel expenses of $16,943 for RZ 1, 18,143 for RZ 2, and $35,299 for RZ 3. (Staff Ex. 11.0, 5-7.) In its surrebuttal filing, Ameren agreed to Staff's recommendation. (Ameren Ex. 35.0, 2.)

As noted above, Staff and Ameren are in agreement on this issue. However, the AG recommends that Ameren place reliance on its actual gasoline and diesel fuel cost from the first four months of 2015 to value its O&M expenses for 2016. (AG Ex. 5.0, 17.) Staff disagrees with the AG's request. In particular, Staff notes that its recommendation relies on gasoline and diesel fuel price projections from the EIA, a Federal entity that collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. (Staff Ex. 5.0, 5.) The AG's proposal simply relies on a snap shot of prices at a set point in time that may or may not bear any resemblance to Ameren's 2016 gasoline and diesel fuel prices. Consequently, Staff recommends that the Commission reject the AG's methodology and its proposed adjustment.

7. Gas-Only Employee Headcount/Vacancy Costs

In its direct filing, Staff expressed concern about Ameren's ability to increase its gas-only headcount in the timeframe and manner proposed by the Company. In particular, Staff noted that, through the end of April 2015, Ameren had projected an increase in headcount of 31 gas-only employees, but only achieved an increase of 11 gas-only employees, a variance of 20 employees. (Staff Ex. 5.0, 10.) Staff also noted that if Ameren's hiring trend continued, then Ameren should revise its expected gas-only headcount for the 2016 test year. (Id. at 11.)

In its rebuttal testimony, Ameren indicated that it had made significant progress in hiring gas-only employees in May and June of 2015. In particular, Ameren noted it only had a variance between projected and actual gas-only positions at the end of June of nine positions rather than the 20 identified by Staff. In addition, Ameren had hired five employees who were expected to start after the end of July 2015, so the Company predicted the variance would be further reduced. (Ameren Ex. 22.0, (2d Rev.), 4.) Ameren also noted that several things factor into the variance, including the amount of attrition, the type of positions Ameren is seeking to fill, and the need to develop a new hiring process for gas apprentices. (Id. at 5.)

Staff's rebuttal filing noted that Ameren had provided Staff with more up-to-date information regarding its gas-only headcount in response to Staff's data request and subsequent to the filing of Ameren's rebuttal testimony. Specifically, Ameren provided information to Staff that indicated it had reduced its projected gas-only employee levels by two people for both 2015 and 2016. (Staff Ex. 11.0, 9.) Further, while Ameren's actual numbers through the end of July 2015 now showed a variance of 14 positions between it's projected versus actual gas-only employee levels at the end of July 2015, Ameren had commitments in place to hire 11 additional employees company-wide in 2015, and was attempting to fill several other positions that could result in additional gas-only hiring in 2015. (Id.) Staff stated it no longer had any concerns with Ameren's assumed levels of gas-only employees. (Id.)

8. Gas Distribution and Transmission Expense

a. Sewer Cross Bore Inspections

b. Gas Records Management

c. Corrosion Control Painting

d. Damage Prevention

e. Gas Technology Institute Operations Technology Development

9. Gas Storage Expense

a. Well-Related Work

b. Compressor-Related Work

10. Sales Forecast – Test Year Billing Determinants

C. Recommended Operating Income Statements

Based on the operating expense statements for the gas utilities originally proposed by AIC for each of its rate zones and Staff's proposed adjustments to operating revenues and expenses as summarized above, the total gas utility net operating income proposed by Staff for rate zone 1 is $21,226,000, for rate zone 2 is $21,836,000, and for rate zone 3 is $47,650,000. The operating expense statements are summarized as follows:

Staff Recommended Operating Statements
(In Thousands)

Description	Rate Zone 1 (CIPS)	Rate Zone 2 (CILCO)	Rate Zone 3 (IP)
Gas Service Revenues	$92,817	$101,459	$202,830
Other Miscellaneous Revenues	1,000	1,122	2,241
Total Operating Revenue	93,817	102,581	205,071
Uncollectible Accounts	890	1,045	1,978
Production Expenses	548	772	1,374
Storage, Term., and Proc. Exp.	2,774	3,904	6,947
Transmission Expenses	2,143	1,744	5,793
Distribution Expenses	22,893	23,455	45,943
Cust. Accounts, Service & Sales	6,184	7,250	14,177
Admin. & General Expenses	13,745	15,269	29,660
Depreciation & Amort. Expenses	11,015	13,985	23,995
Taxes Other Than Income	3,261	4,135	7,793
Total Operating Expense Before Income Taxes	63,453	71,559	137,660
State Income Tax	1,174	1,120	2,335
Federal Income Tax	4,889	4,671	9,731
Deferred Taxes and ITCs	3,075	3,395	7,695
Total Operating Expenses	72,591	80,745	157,421
NET OPERATING INCOME	$21,226	$21,836	$47,650

IV. COST OF CAPITAL AND RATE OF RETURN

Four witnesses submitted testimony regarding Ameren's cost of capital. On behalf of Ameren, Mr. Robert B. Hevert presented testimony regarding the Company's cost of common equity and Mr. Ryan J. Martin presented testimony regarding the Company's proposed capital structure and overall weighted average cost of capital ("WACC"). (Ameren Exs. 5.0(Rev.), 5.1-5.8; 5.9 (Rev.) 5.10-5.12; *see generally* Ameren Exs. 4.0(Rev.), 4.1 (Rev.), 4.2, 4.3.) On behalf of the IIEC/CUB, Mr. Michael Gorman presented testimony regarding the Company's cost of common equity. (IIEC/CUB Joint Exs. 1.0-1.17.) On behalf of Staff, Ms. Sheena Kight-Garlisch presented testimony regarding the Company's cost of common equity, capital structure, and WACC. (Staff Exs. 3.0, 9.0.)

A. Resolved/Uncontested Issues

No party contested the appropriate capital structure. Ameren Illinois's capital structure for the forecasted average ("average") year 2016 is comprised of 1.34% short-term debt, 47.43% long-term debt, 1.23% preferred stock and 50.00% common equity. (Ameren Ex. 4.0, 9; Staff Ex. 3.0, 3-4.)

1. Short-Term Debt

Staff estimated that Ameren's cost of short-term debt is 0.45%. Ameren's predominate source of short-term debt is commercial paper, which is rated A2/P2 from the rating agencies. To estimate Ameren's cost of short-term debt, Staff converted the May 27, 2015, 0.44% discount rate on 30-day, A2/P2 commercial paper into an annual yield of 0.45%. (Staff Ex. 3.0, 5.) Ameren accepted Staff's cost of short-term debt. (Ameren Ex. 17.0, 6.)

2. Long-Term Debt

Staff estimated that Ameren's embedded cost of long-term debt for the average 2016 measurement period equals 5.79%. (Staff Ex. 3.0, 6.) Staff adjusted the Company's embedded cost of long-term debt to reflect Staff's forecasted coupon rates of 4.03% and 3.04% for the 2015 and 2016 issuances, respectively. (Staff Ex. 3.0, 6.) Ameren accepted Staff's cost of long-term debt. (Ameren Ex. 17.0, 6.)

3. Preferred Stock

Company and Staff agree that Ameren's embedded cost of preferred stock is 4.98%. (Ameren Ex. 4.0, 19; Staff Ex. 3.0, 6.)

4. Common Equity

AIC, IIEC, CUB and Staff (collectively referred to as the "Stipulating Parties") have agreed to a 9.60% return on equity ("ROE") for the purpose of setting Ameren Illinois' gas rates. (Staff Ex. 9.0, 1; Ameren Ex. 32.1.) Staff believes the 9.60% ROE agreed to by the Stipulating Parties is a reasonable resolution of the issue for the purposes of this proceeding. However, Staff's participation in an ROE stipulation should not be construed as endorsement or validation of any of the methodologies or inputs used by Mr. Hevert to develop his estimates of the Company's ROE. (Staff Ex. 9.0, 1.)

Given the above, Staff recommends that the Commission approve an ROE of 9.60% for Ameren Illinois.

B. Contested Issues (NA)

C. Recommended Overall Rate of Return

1. Stipulated Cost of Common Equity

The overall rate of return for Ameren Illinois, incorporating the stipulated cost of common equity of 9.60%, is 7.65%, as shown in the table on the following page. (Staff Ex. 9.0, 2 and Schedule 9.02.)

Ameren Illinois Company
Weighted Average Cost of Capital

Staff's Proposal
Average 2016

	Percent of Total Capital	Cost	Weighted Cost
Long-term Debt	47.43%	5.79%	2.75%
Short-term Debt	1.34%	0.45%	0.01%
Preferred Stock	1.23%	4.98%	0.06%
Common Equity	50.00%	9.60%	4.80%
Bank Facility Costs			0.04%
Total Capital	100.00%		
Weighted Average Cost of Capital			**7.65%**

2. Cost of Common Equity Should Commission Decline to Adopt Stipulation in its Entirety

While Staff supports entry of the terms pursuant to the Stipulation entered into by AIC, IIEC, CUB, and Staff on July 29, 2015 (Ameren Ex. 32.1), pursuant to paragraph 11 of the Stipulation, in the event the Commission declines to adopt the Stipulation in its entirety, the parties can advance contrary arguments. In the event that were to occur, Staff sets forth the following arguments in support of its ROE analysis.

a. Overview of ROE Analysis

Three parties presented estimates of Ameren's cost of common equity: AIC, IIEC/CUB, and Staff. The Company estimated its ROE to be 10.25%. (Ameren Ex. 5.0, 3, 6, 43.) IIEC/CUB witness Gorman proposes to use a 9.25% cost of common equity. (IIEC/CUB Joint Ex. 1.0, 2, 38-39.) Staff estimated the Company's ROE to be 9.31%. (Staff Ex. 3.0, 30-32.)

b. Ameren's Analysis

Company witness Hevert applied the Non-Constant Discounted Cash Flow ("NCDCF") model and the Capital Asset Pricing Model ("CAPM") to a sample of eight natural gas companies to derive his cost of common equity for Ameren Illinois. Mr. Hevert calculated four estimates of the ROE with the CAPM. Two of Mr. Hevert's CAPM ROE estimates are based on a market return derived from Bloomberg data and two are based on a market return derived from Value Line data. Mr. Hevert also presented, but did not rely upon, an Alternative CAPM and the bond yield plus risk premium approach. From those analyses he derived the following estimates:

Model	**Sample Estimate**
NCDCF	9.12%-9.84%
CAPM -Bloomberg	10.55%-10.59%
CAPM-Value Line	10.55%-10.59%

Mr. Hevert concluded that the cost of common equity for Ameren is 10.25%. (Ameren Ex. 5.0, 2, 21, 25, 43.)

c. IIEC/CUB Analysis

IIEC/CUB witness Gorman estimated Ameren's cost of common equity with four separate analyses: (1) a constant growth Discounted Cash Flow ("DCF") utilizing consensus analyst growth rates; (2) DCF utilizing sustainable growth rates (3) NCDCF; and (4) CAPM. Mr. Gorman applied these models to the same sample of eight natural gas companies as Mr. Hevert. Mr. Gorman derived the following estimates from his four analyses:

Model	**Sample Estimate**
DCF-Analyst Growth	8.71%
DCF-Sustainable Growth	10.09%
NCDCF	8.27%
CAPM	9.50%

Mr. Gorman averaged his three DCF based analyses to estimate a DCF return on equity of 9.0%. He then averaged his average DCF estimate and his CAPM estimate to get his recommended cost of equity for Ameren of 9.25%. (IIEC/CUB Joint Ex. 1.0, 29, 38-39.)

d. Staff's Analysis

Staff witness Sheena Kight-Garlisch estimated Ameren's investor-required rate of return on common equity to be 9.31%. Ms. Kight-Garlisch measured the investor-required rate of return on common equity with NDCF and CAPM analyses. She began with the data that Mr. Hevert used in his NCDCF and CAPM analyses, but corrected the most significant flaws in those analyses. Ms. Kight-Garlisch applied those models to Mr. Hevert's sample of eight natural gas utility companies ("Gas Sample"). (Staff Ex. 3.0, 7.)

(1) 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 companies in Ms. Kight-Garlisch's Gas Sample pay dividends quarterly. Therefore, Ms. Kight-Garlisch applied a quarterly NDCF model. (Staff Ex. 3.0, pp. 7-8.)

DCF methodology requires a growth rate that reflects the expectations of investors. A single-stage, constant growth DCF model employs a single growth rate estimate, which is assumed to be sustainable to infinity. Thus, the cost of common equity calculation derived from a constant growth estimate DCF is correct only if the near-term growth rate forecast for the sample as a group is expected to approximate its average long-term dividend growth. Ms. Kight-Garlisch implemented the NCDCF model in this proceeding because the level of growth indicated by the average 3-5 year growth rate for the Gas Sample is not sustainable over the long-term. The average 3-5 year growth rate was 5.2% for the Gas Sample, while Staff's estimate of the long-term growth rate was 4.4%. In theory, no company could sustain a growth rate greater than that of the overall economy indefinitely, or it would eventually grow to dominate the entire economy. Moreover, since utilities in particular are generally below-average growth companies, the sustainability of an above-average growth rate is particularly dubious. Given that the average growth rate for the Gas Sample is greater than the overall growth expectations for the economy, the sustainability of the average 3-5 year growth rates for the Gas

Sample is unlikely. Therefore, Ms. Kight-Garlisch implemented a NCDCF. (Staff Ex. 3.0, 8-9.)

Ms. Kight-Garlisch's NCDCF model incorporated three stages of dividend growth. The first or a near-term growth stage is assumed to last five years. To estimate the growth rate for the first stage, Ms. Kight-Garlisch started with the earnings per share ("EPS") growth estimates from Zacks and Value Line, as presented by Mr. Hevert on Ameren Illinois Ex. 5.1. Ms. Kight-Garlisch also included the Bloomberg Professional ("Bloomberg") EPS growth estimates and Value Line dividend per share ("DPS") growth estimates. In order to give equal weight to each growth estimate source, she averaged the Value Line EPS and DPS growth estimates into a single Value Line growth projection. She then computed the average of the growth estimates from Zacks, Bloomberg, and the average Value Line growth projection. The first stage growth estimates average 5.2% for the Gas Sample. (Staff Ex. 3.0, 11-12.)

The second stage is a transitional growth period that spans from the beginning of the sixth year through the end of the tenth year. The growth rate employed in the transitional growth period equals the average of the near-term stage growth rate (first stage) and the "steady-state" stage growth rate (third stage). (Staff Ex. 3.0, 12.)

The third, or "steady-state," growth stage commences at the end of the tenth year and is assumed to last into perpetuity, Ms. Kight-Garlisch calculated forecasted nominal GDP growth beginning in 2024 to estimate the long-term growth expectations of investors. The nominal GDP growth rate is composed of two parts, the expected real growth rate and the expected inflation rate. She estimated the expected real growth rate from the average of the Energy Information Administration ("EIA") and IHS Global Insight's ("IHS") forecasts of real GDP. EIA forecasts that real GDP will average 2.4% over the 2024-2040 period. Similarly, IHS forecasts that real GDP will average 2.3% over the 2024-2044 period. Ms. Kight-Garlisch averaged the EIA (2.4%) the IHS (2.3%) real GDP forecasts to calculate her 2.3% long-term estimate of real GDP growth. (Staff Ex. 3.0, 12.)

Ms. Kight-Garlisch extrapolated an estimate of the expected inflation rate from the difference in yields on U.S. Treasury bonds, which contain a premium for expected inflation, and U.S. Treasury Inflation-Protected Securities ("TIPS"), which do not contain a premium for expected inflation. The formula for this calculation is:

$$\text{Expected inflation} = (1+\text{UST}) / (1+\text{TIPS}) - 1$$

Where UST = yield on U.S. Treasury bonds; and
TIPS = yield on U.S. Treasury Inflation-Protected Securities.

An implied 20-year forward TIPS yield in ten years of 1.19% was derived from the 0.39% 10-year and 0.92% 30-year TIPS rates for November 28, 2014. An implied 20-year forward U.S. Treasury rate in ten years of 3.25% was derived from the 2.18% 10-year and 2.89% 30-year U.S. Treasury rates for November 28, 2014. The implied 20-year forward rates were calculated using the following formula:

$${}_{20}f_{10} = [(1+{}_{30}r_0)^{30} / (1+{}_{10}r_0)^{10}]^{1/20} - 1$$

Where ${}_{20}f_{10}$ = the implied 20-year forward rate in ten years;
${}_{30}r_0$ = the current 30-year rate; and
${}_{10}r_0$ = the current 10-year rate.

Therefore, the estimate of long-term expected inflation equals 2.0%:

$$(1 + 3.25\%) / (1 + 1.19\%) - 1 = 2.0\%.$$

The two components of nominal overall economic growth were then combined to estimate the long-term growth rate for the third stage, using the following formula:

Nominal GDP growth= [(1+Real GDP) * (1+Inflation)] – 1

Therefore, from the long-term estimates of real GDP growth of 2.3% and expected inflation of 2.0%, the long-term estimate of nominal GDP growth equals 4.4%:

Nominal overall economic growth = (1 + 2.3%) * (1 + 2.0%) – 1 = 4.4%

Ms. Kight-Garlisch also calculated the nominal economic growth EIA forecasted for the 2024-2040 period (4.4%) and IHS forecasted for the 2024-2044 period (4.4%). Finally, she averaged the 4.4% midpoint of the EIA and IHS forecasts with the 4.4% nominal GDP growth estimate described above to derive her estimate of long-term growth of 4.4%. (Staff Ex. 3.0, 12-14.)

Ms. Kight-Garlisch's NCDCF estimate of the required rate of return on common equity for the Gas Sample is 8.12%. (Staff Ex. 3.0, 15.)

(2) Risk Premium Analysis

According to financial theory, the required rate of return for a risky security equals the risk-free rate of return plus a risk premium associated with that security. The risk premium methodology is consistent with investors' aversion to risk. 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. Kight-Garlisch used a one-factor risk premium model, the Capital Asset Pricing Model ("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, 15-16.)

The CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market. For the beta parameter, Ms. Kight-Garlisch supplemented Mr. Hevert's Value Line betas with the Zacks betas and betas calculated using a regression analysis. (Staff Ex. 3.0, 20.) The Gas Sample's average Value Line, Zacks, and regression beta estimates were 0.79, 0.74, and 0.73, respectively. The Value Line regression employs 259 weekly observations of stock return data regressed against the New York Stock Exchange ("NYSE") Composite Index. Both the regression beta and Zacks betas employ sixty monthly observations; however, while Zacks betas regress stock returns against the S&P 500 Index, the regression beta regresses stock returns against the NYSE Index. Since the Zacks beta estimate and the regression beta estimate are calculated using monthly data rather than weekly data (as Value Line uses), Ms. Kight-Garlisch averaged the Zacks and regression results to avoid over-weighting monthly return betas. She then averaged that result with the Value Line beta, which produced a beta for the Gas Sample of 0.76. (Staff Ex. 3.0, 20-24.) For the risk-free rate parameter, Ms. Kight-Garlisch considered the 0.04% yield on four-week U.S. Treasury bills and the 2.89% yield on thirty-year U.S. Treasury bonds. Both estimates were measured as of November 28, 2014. For a growing economy with inflation, such as that of the U.S., a long-term risk-free rate near zero is implausible; therefore, the U.S. Treasury bond yield of 2.89% currently more closely approximates the long-term risk-free rate than the U.S. Treasury bill yield of 0.04%. (Staff Ex. 3.0, 16-19.)

Finally, for the expected rate of return on the market parameter, Ms. Kight-Garlisch conducted a DCF analysis on the firms composing the S&P 500 Index as of September 30, 2014[3]. That analysis estimated that the expected rate of return on the market equals

[3] Firms not paying a dividend as of September 30, 2014, or for which neither Zacks nor Reuters growth rates were available were eliminated from the analysis.

12.40%. (Staff Ex. 3.0, 19-20.) Inputting those three parameters into the CAPM, Ms. Kight-Garlisch calculated a cost of common equity estimate of 10.12% for the Gas Sample. (Staff Ex. 3.0, 24.)

(3) Cost of Common Equity Recommendation

Ms. Kight-Garlisch estimated the investor required rate of return on common equity for the Gas Sample from the results of the NCDCF and CAPM analyses. The average investor required rate of return on common equity for the Gas Sample, 9.12%, is based on the average of the DCF derived results (8.12%) and the risk premium derived results (10.12%). (Staff Ex. 3.0, 26.) She then added a risk premium to reflect the higher level of overall risk of Ameren relative to the Gas Sample. Adding a 0.19% risk adjustment to the 9.12% Gas Sample average, results in a 9.31% estimate of the Company's cost of common equity. (Staff Ex. 3.0, 26.)

Ms. Kight-Garlisch assessed the comparability of the overall risk of Ameren versus the Gas Sample. The credit ratings assigned to a company reflect both business and financial risk. Since credit ratings reflect a company's overall risk, she compared the credit ratings of the Gas Sample and Ameren. The Gas Sample has an average credit rating of A-/A3/A- from the three rating agencies. Ameren has a credit rating of BBB+/A3/BBB+ by the rating agencies. Whereas Moody's rates Ameren at the same average rating as the Gas Sample, both S&P and Fitch rate Ameren one credit rating notch lower. Thus, the Gas Sample's average credit rating indicates that it is slightly less risky than Ameren. Financial theory posits that investors require higher returns to accept greater exposure to risk. Conversely, the investor-required rate of return is lower for investments with less exposure to risk. Thus, in Ms. Kight-Garlisch's judgment, given the difference between the credit ratings for the Company and the average credit rating of the Gas Sample, the Sample's average cost of common equity should be adjusted upward to determine the final estimate of the Company's cost of common equity. (Staff Ex. 3.0, 26-27.)

To estimate the appropriate risk adjustment, Ms. Kight-Garlisch began with the spread between long-term utility bonds rated A and Baa by Moody's. According to Moody's, on May 26, 2015 A-rated long-term utility bonds yielded 4.15%, while Baa rated long-term utility bonds yielded 4.88%. Since the Gas Sample and Ameren credit ratings average only two-thirds of a ratings notch apart and each credit rating is subdivided into three ratings notches (e.g., Baa1, Baa2, Baa3) she then divided the 0.73% spread by 3 to estimate the incremental yield for a single ratings notch. This results in a 0.24% yield spread per notch. Ms. Kight-Garlisch also considered the Value Line long-term utility bond yields of 4.16% for A-rated utility bonds and 4.55% for Baa rated utility bonds. Dividing this 0.39% spread by three results in a 0.13% yield spread per notch. She then took a simple average of the two, resulting in the 0.19% upward financial risk adjustment to the cost of common equity estimate for the Gas Sample. Adding the 0.19% financial risk adjustment to the 9.12% cost of common equity estimate for the Gas Sample, results in an investor-required rate of return on common equity for Ameren of 9.31%. (Staff Ex. 3.0, 27.)

V. COST OF SERVICE

A. Resolved/Uncontested Issues

1. Use of AIC's Cost of Service Study (but for V.B.1.)

Staff does not object to the use of AIC's proposed cost of service studies ("COSSs") in this proceeding. AIC filed three different COSSs, one for each rate zone, which show the revenue requirement for each rate class necessary to achieve equalized rates of return on investment. (AIC Ex. 9.0 (Rev.), 3.) Generally, AIC prepared the COSSs utilizing three major steps: (1) cost functionalization,[4] (2) cost classification,[5] and (3) cost allocation[6] of all the costs of the utility's system to customer classes. (Id. at 6.) AIC's COSSs generally use the same methodologies and allocators the Commission approved at the conclusion of AIC's last gas rate case. (Id. at 8, 2013 Gas Rate Final Order.)

AIC proposes to maintain its current rate classes for all three rate zones: GDS-1 Residential Delivery Service; GDS-2 Small General Delivery Service; GDS-3 Intermediate Delivery Service; GDS-4 Large General Delivery Service; GDS-5 Seasonal Gas Delivery Service; and GDS-7 Special Contract. (AIC Ex. 9.0 (Rev.), 3-4.) AIC employs these rate class definitions to allocate costs and to design rates to recover those costs.

AIC's functionalization methodology is consistent with the Commission's Uniform System of Accounts, 83 Ill. Adm. Code Sec. 505, which groups plant and expenses into various functions such as production, storage, transmission, or distribution. (AIC Ex. 9.0 (Rev.), 8.) AIC's classification methodology functionalizes plant and expenses based on

[4] Plant costs (*i.e.* investments) and related operation, maintenance, depreciation and tax expenses are assigned to the basic functions of production, storage, transmission, and distribution. (American Gas Association Rate Committee, American Gas Association Gas Rate Fundamentals, 135 (4th edition, 1987).)

[5] Each functional cost is further divided by cost causation into: (1) demand costs (costs that relate to the peak usage of utility service by the company's customers); (2) commodity costs (variable costs that reflect the number of units consumed or supplied during a period of time); and (3) customer costs (fixed distribution and customer accounting costs directly allocated to customers, *e.g.*, metering costs). Id. at 136-137.

[6] Each classified cost is allocated to rate classes using allocation factors. Id. at 137.

how the expenses are incurred: commodity-related, demand-related, and customer-related[5]. (Id. at 8.) These methodologies were used and approved by the Commission in AIC's previous gas rate cases, and Staff does not object to their use in this proceeding.

2. Allocation of Underground Storage Assets

3. Rate Zone Allocation of Plant Additions after September 30, 2010

Staff recommends the Commission approve AIC's proposed modification to the allocation factors for transmission and distribution ("T&D") plant additions made subsequent to September 30, 2010.

AmerenCIPS, AmerenCILCO, and AmerenIP became one entity known as Ameren Illinois Company, effective September 30, 2010. (*Central Illinois Light Company d/b/a AmerenCILCO Central Illinois Public Service Company d/b/a AmerenCIPS Illinois Power Company d/b/a AmerenIP*, Petition for accounting order, ICC Final Order, Docket No. 10-0517, 20-21 (Mar. 15, 2011).) ("Final Order 10-0517") These three legacy utilities became rate zones within AIC denoted as Rate Zone I, Rate Zone II, and Rate Zone III, respectively. Any plant in service costs incurred prior to September 30, 2010 are assigned to rate zones based on historical plant in service cost information from the legacy utility. (AIC Ex. 2.0 (Rev.), 24.) Costs incurred subsequent to this date are recorded at the AIC level and are allocated to rate zones using various allocation factors. (Id. at 24-25.)

AIC proposes to modify the allocation factors for T&D plant additions subsequent to September 30, 2010. (Id. at 25.) Specifically, AIC proposes to use the peak and average allocation factor for these plant additions. (AIC Ex. 2.6, 1-2.) AIC believes its proposed modification to these allocation factors better aligns with cost causation because AIC has made plant additions and replaced older depreciated plant since 2010, so current plant balances by rate zone are not expected to be at the 2010 level. (Id.)

Staff recommends the Commission approve AIC's proposed modification to the allocation factors for T&D plant additions made subsequent to September 30, 2010. This modification better aligns with cost causation, since transmission and distribution plant additions within rate zones are currently allocated based on peak and average demand.[7] Furthermore, this modification serves as a good transition for uniform rates because once all rates are uniform, all transmission and distribution plant additions will be allocated based on peak and average demand.

B. Contested Issues

1. Allocation of Demand-Related T&D Costs

The Commission should accept AIC's proposal to use the Peak and Average Method to allocate demand-related T&D costs. This is the same methodology used and approved by the Commission in AIC's previous gas rate cases, Docket Nos. 13-0192 and 11-0282, which allocated T&D costs based on a Peak and Average Method, using a combination of Design Day Demand and Average Demand. (Id. at 9.) Staff does not object to the Peak and Average Method. (Staff Ex. 4.0, 10.)

IIEC recommends the Commission determine the Design Day Method to be the most appropriate cost of service allocation method for T&D main costs, which IIEC states is also known as the Coincident Demand method. (IIEC Ex. 1.0, 2, 23.) In support of this

[7] AIC's prior two rate cases, Docket Nos. 11-0282 and 13-0192, both allocate transmission and distribution plant within rate zones based on peak and average demand. AIC proposes to continue to allocate transmission and distribution plant within rate zones based on peak and average demand. (AIC Ex. 9.0 (Rev.), 9.)

recommendation, IIEC argues that the use of the Design Day Method best reflects cost causation because the Company designs its T&D main system to meet the peak demands of its customer classes. IIEC states that the Design Day allocation factor ensures that all customers will pay for the capacity necessary to ensure delivery of their firm demands. (Id. at 23.)

The Design Day allocation factor proposed by IIEC allocates the T&D main costs based on each customer class's demand at the time of the system peak. The Peak and Average allocation factor proposed by AIC utilizes the Design Day in part for the Peak component as described in the previous statement, and the Average component in part. The Average component is computed by weighting average daily deliveries of gas by the system average load factor.[8] In AIC Ex. 24.0, Table 2, AIC witness Schonhoff illustrates the weighting of the Peak and Average factors derived from the Peak and Average Method by rate zone, which shows that the Peak component comprises the larger portion of the allocation factor. (AIC Ex. 24.0, 12.)

Peak demands are used in designing the T&D system, but, according to AIC, this is not the only factor taken into consideration by the Company. Mr. Schonhoff states that AIC engineers also use peak hourly demand and operating pressure to determine service adequacy. (AIC Ex. 24.0, 7.) In other words, the Company must also consider demand patterns throughout the year in addition to meeting demand during the system peak. This is important because demand must exist throughout the year to generate enough revenue

[8] Daily average gas deliveries are calculated by dividing total annual throughput by 365 days; the system average load factor is calculated by dividing daily average gas deliveries by peak day gas deliveries.

to recover the utility's fixed costs and make the investment viable. Additionally, the system is not in use solely for the coldest days of the year, but rather for every day of the year.

Allocating all T&D mains based on peak demand assumes that T&D investments are all system peak-related, which ignores the fact that the Company considers other factors such as different demand patterns throughout the year through peak hourly demand and also operating pressure to meet reliability.

Cost causation should be determined by which allocation factor most appropriately fits the evidence presented in this proceeding. Given how the Company designs the system, the Design Day allocation factor does not take into account these other factors. If the Design Day allocation factor is utilized as IIEC proposes, approximately $6 million of revenue requirement responsibility would be shifted onto the residential class; approximately $5.5 million of revenue responsibility would be removed from the GDS-4 customer class; and cost allocation of all T&D mains to the GDS-5 customer class would be completely eliminated. (AIC Ex. 24.0, 2.)

Furthermore, the Design Day allocation factor does not allocate any costs associated with T&D mains to the GDS-5 customer class. Therefore, the Design Day allocation method shifts the GDS-5 class costs associated with T&D mains to all remaining customer classes. However, the GDS-5 class utilizes T&D mains for natural gas consumption and proportionate costs associated with that use should be allocated to the class. Since no T&D main costs are assigned to the GDS-5 customer class, the Design Day allocation factor does not reflect cost causation for this customer class.

Based on how the Company designs its T&D system, the Peak and Average allocation factor better reflects the cost causation of the Company's system because it accounts for other factors besides peak demand, such as peak hourly demand throughout the year. Additionally, the Design Day method does not allocate costs associated with T&D mains to the GDS-5 customer class and thus does not represent cost causation accurately for this customer class.

VI. REVENUE ALLOCATION

A. Resolved/Uncontested Issues

1. Rate Mitigation

The Commission should accept Ameren's proposed revenue allocation. Ameren proposes movement toward cost-based rates to recover each customer class's revenue requirement, assuming an equalized rate of return as determined by the COSSs constrained to a maximum of 1.5 times the overall average increase to the respective rate zone. (AIC Ex. 10.0, 11.) This methodology mitigates the concern of adopting the full cost of service results and the prospect of unfavorable rate impacts that could otherwise result for some rate classes. The amount of revenue requirement which is unrecovered, because the rate increase would exceed the cap, would be allocated to the other rate classes, *i.e.*, recovered from the rate classes that have not reached the cap. (Staff Ex. 4.0, 31-32.)

The 1.5 rate constraint represents a reasoned judgment of how much progress can be made towards cost-based revenue allocations while minimizing bill impact concerns. In the last AIC gas rate case, the Commission approved the same 1.5 times the overall average increase rate constraint. (2013 Gas Rate Final Order, 209.) In Docket Nos. 09-0306 – 09-0311 (Cons.), the Commission also noted a desire to eliminate rates that differ from cost of service, and stated "[c]ontinued movement toward cost-based rates and the elimination of inter-class and intra-class subsidies should be a considered priority." (*Central Illinois Light Company d/b/a AmerenCILCO*, Proposed general increase in electric delivery service rates, ICC Final Order Docket Nos. 09-0306 – 09-0311 (Cons.), 260 (May 6, 2010).)

B. Contested Issues (NA)

VII. RATE DESIGN

A. Resolved/Uncontested Issues

1. Rate Uniformity

The Commission should accept Ameren's proposal to move toward rate uniformity. In Docket No. 10-0517, the Commission rejected complete rate uniformity, noting that combining all class rates across all rate zones would unfairly benefit some customers and harm other customers based on the legacy utilities. (Final Order 10-0517, 20-21.) Since that order, the Commission has made steps toward rate uniformity and has endorsed such movement toward single-tariff pricing. (2013 Gas Rate Final Order, 180.)

If the rate zone level costs for a rate class are within 10% of the total combined class average costs, AIC proposes that the costs are close enough to implement rate uniformity within that customer class. (AIC Ex. 10.0, 9.) When rate zone level costs are greater than 10% of the total combined class average costs, AIC limits progress toward uniform pricing, although still proposes steps toward rate uniformity for that customer class. Based on these parameters, AIC proposes rate uniformity for the GDS-1, GDS-2, and GDS-3 customer classes. (AIC Ex. 10.0, 9-10.) Since costs are within 10% of the combined average for all rate zones for each of these customer classes, it is appropriate at this time for uniform rates for these rate classes.

AIC proposes movement toward rate uniformity for GDS-4 and GDS-5 customer classes for the various charges since rate zone level costs are not with 10% of the total combined class average costs. (AIC Ex. 10.0, 14, 16; Ill. C.C. No. 2 8th Revised Sheet No. 14.002, Ill. C.C. No. 2 6th Revised Sheet No. 14.004; Ill. C.C. 8th Revised Sheet No. 15; Ill. C.C. 8th Revised Sheet No. 15.001). This is consistent with the progression of the Commission's repeated goal of moving toward single-tariff pricing at a level appropriate given the rate differences within these classes.

2. Charges for GDS-3, GDS-4, and GDS-5

The Commission should accept AIC's proposed rate design for GDS-3, GDS-4, and GDS-5 customer classes. The following proposed charges are based on AIC's proposed revenue requirement, which will be adjusted based on the final revenue requirement.

For the GDS-3 customer class, AIC proposes Customer Charges of $48.96 for customers with annual gas usage of 600 therms or less and $82.00 for customer with annual gas usage over 600 therms. (Ill. C.C. No. 2 6th Revised Sheet No. 12.) AIC proposes $0.08614 per therm for the Distribution Delivery Charge for customers receiving gas supply under Rider S and $.0.4525 per therm for customers receiving gas supply under Rider T. (Ill. C.C. No. 2 6th Revised Sheet No. 12.001.)

For the GDS-4 customer class, AIC proposes the Customer Charge for customers with MDCQ of less than or equal to 10,000 therms remain at $600 for all rate zones, and a Customer Charge for customers with MDCQ greater than 10,000 therms be set at $1,200 for all rate zones. (AIC Ex. 10.0, 14.) AIC also proposes to eliminate the

Distribution Delivery Charges for all rate zones and increase the Demand Charges accordingly. (Id.)

For the Demand Charge for Rate Zone II, AIC proposes rates that move toward eliminating the usage differentiation, and eliminates this differentiation for Rider S customers and also for gas main MAOP greater than 60 psig for Rider T customers. (Ill. C.C. No. 2 8th Revised Sheet No. 14.002.) AIC proposes rates for the MDCQ Overrun Charge that eliminate the usage differentiation for Rider S customers and for gas main MAOP greater than 60 psig for Rider T customers. (Ill. C.C. No. 2 6th Revised Sheet No. 14.004.)

For the GDS-5 customer class, AIC proposes a uniform Customer Charge of $350.00 for customers with MDCQ less than 3,250 therms, and a uniform Customer Charge of $750.00 for customers with MDCQ greater than or equal to 3,250 therms. (AIC Ex. 10.3, 7.) AIC proposes $0.07588 per therm for the Distribution Delivery Charge for Rider S customers and $0.01882 per therm for Rider T customers for Rate Zones II and III. (Id.) AIC proposes $0.05761 per therm for the Distribution Delivery Charge for Rate Zone I for Rider S customers and $0.01429 per therm for Rider T customers. (Id.) ICC Staff Witness Alicia Allen created ICC Staff Ex. 4.0, Schedule 4.06, which shows the current and proposed Demand Charges for all rate zones.

For the GDS-3, GDS-4, and GDS-5 customer classes, AIC's proposed rates move toward rate uniformity and are determined by the COSS. This is consistent with the rate principle of assigning charges based on cost causation and therefore should be accepted.

3. Space Heat Study (contingent upon VII.B.1.)

The Commission directed AIC to provide in its next gas rate proceeding a study ("Space Heat Study") reporting information regarding the bifurcation of the GDS-1 rate class into heating and non-heating subclasses. (2013 Gas Rate Final Order, 195.) This information is to include a method for distinguishing between heating and non-heating customers and the estimated costs; the timeframe necessary to program AIC's billing system to distinguish between heating and non-heating customers; and estimates of the cost to serve the two groups of customers. (Id. at 194.)

AIC determined the space heat indicator flag within their billing system to be inaccurate. Therefore, AIC suggests the following three options to determine space heat customers: (1) AIC could conduct a verbal or mail survey in an attempt to update its records, which AIC notes would likely need to be supplemented by audits described in Option 2; (2) AIC could conduct a physical, in-home inspection of primary heating sources; or (3) AIC could develop a usage threshold based on historical, customer-specific data to estimate end use heating type. (AIC Ex. 10.0, 20.)

AIC estimates that the survey or series of surveys contemplated by Option (1) would cost approximately $6.3 million, with additional costs for in-home inspection activities that may be necessary to obtain a more reliable response rate. (Id. at 21.) AIC estimates the cost of Option (2), stand-alone in-home inspections, would vary dramatically based on response rate, and could climb to approximately $49.5 million for a 100% response rate. (Id.) AIC estimates the "historical use" proxy contemplated by Option (3) would cost approximately $60,000. (Id.)

Staff's recommendation is contingent on the rate design accepted by the Commission. Should the Commission accept Staff's rate design proposal to reduce the

Customer Charge from 80% to 70% of the revenue requirement, or any greater reduction to the Customer Charge in a movement to recover only customer-related costs through the Customer Charge, then Staff recommends the Commission not require AIC to select any of the options to bifurcate the GDS-1 customer class into heating and non-heating subclasses. The COSS determined customer-component costs for the GDS-1 customer class is 53.53%. By accepting Staff's proposal to reduce the percentage of revenues recovered through the Customer Charge from 80% to 70%, or any further reduction in revenues recovered through the Customer Charge, the Commission would be taking a step toward recovering only COSS-determined customer component costs through the Customer Charge. Should the Company continue collecting higher percentages of the revenues required through the Customer Charge, some demand-component costs will be recovered through the Customer Charge, resulting in lower-use customers paying higher demand component costs despite not actually placing higher demands on the system. Theoretically, if the Customer Charge was set at the COSS determined amount of 53.53% of the revenues required, then lower-use customers would no longer pay for excess demand component costs. Staff believes a bifurcation of the GDS-1 customer class is unnecessary at this time if rates are established based on movement toward the COSS determined cost components. (Staff Ex. 4.0, 48.)

However, if the Commission decides to remain at greater fixed cost recovery through the Customer Charge, Staff recommends the Commission select the historical use proxy option (Option 3) with one modification. Rather than trying to verify the accuracy of the number of heating and non-heating customers, the Commission could subdivide the GDS-1 customer class based on usage. Those that consume lower amounts of gas on average during the year would have similar consumption and demand characteristics. It could be more appropriate to place these customers into their own customer subclass to reflect their true costs on the system regardless of whether they are a space heating or a non-space heating customer. As reported in AIC Ex. 10.7, AIC already has usage broken down between residential customers whose average monthly usage is 30 therms and below and residential customers whose average monthly usage is greater than 30 therms. (AIC Ex. 10.7, 7.)

If the Commission determines that the GDS-1 customer class should be bifurcated in the next AIC gas rate proceeding, then Staff recommends AIC be required to provide COSSs that report GDS-1 rates with and without a bifurcation of GDS-1 customers with average monthly usage of 30 therms and below and average monthly usage of greater than 30 therms. This bifurcation would provide the Commission the information necessary to determine if the GDS-1 customer class should be subdivided. Staff also recommends the Commission direct AIC to complete the necessary billing changes before the conclusion of the next proceeding. AIC estimates the time to complete the programming changes to be 3-4 months, and the changes would need to be completed before the conclusion of the instant rate case in order for the bifurcation of the GDS-1 customer class to occur after the conclusion of the Company's next gas rate case proceeding. (Id.) Finally, Staff recommends AIC name the subclasses based on usage level instead of heating versus non-heating to avoid potential customer confusion. Given the Company's admission that it has inaccurate data concerning which customers utilize gas for space heating, customers who are inadvertently erroneously classified as heating customers by the Company could become confused. (Staff Ex. 4.0, 51.)

AIC accepted Staff's proposed recommendations. (AIC Ex. 25.0, 6.)

B. Contested Issues

1. Use of Straight Fixed Variable (SFV) Design / Setting the Customer Charge in GDS-1 and GDS-2

The Commission should adopt Staff's recommendation to reduce the Customer Charge to recover 70% of the revenues required for both the GDS-1 and GDS-2 customer classes instead of the current 80% recovery of the revenues required proposed by Ameren. (Staff Ex. 4.0, 20.) This recommendation is consistent with the policies the Commission articulated in Docket Nos. 13-0387; 13-0476; and 14-0224/14-0225 (Cons.) for conservation, equitable cost sharing within customer classes, and reflects traditional rate design principles of aligning customers' bills with the COSS, while still protecting customers from rate shock. (Id. at 20-21.) Staff also recommends the Commission accept AIC's proposed Rider VBA, as modified to recover 30% of the revenue requirement rather than the 20% proposed by the Company in direct testimony. (Id. at 24.) AIC accepted Staff's proposals in rebuttal testimony. (AIC Ex. 23.0, 5.)

AG witness Rubin proposes rates for the GDS-1 customer class based on the COSS (AG Ex. 3.0, 30.), which have the effect of reducing the Customer Charge to collect approximately 54% of the revenues required. (Id. at 20-21.)

In support of this proposal, Mr. Rubin argues that larger customers incur additional costs for meters and regulators (Id. at 6.), and collecting 80% of the revenue requirement through the Customer Charge has the effect of assuming that metering costs, service line costs, as well as other costs that can vary with the gas demands of the customer are essentially the same for all customers. (Id. at 8.)

Mr. Rubin also cites Section 8-104(c) of the Act that requires specific reductions in the use of natural gas on an annual basis, and argues that high Customer Charges undermine this public policy objective by reducing the Distribution Delivery Charge, which is the part of the customer bill that can be reduced through conservation and energy efficiency. (Id. at 17.)

Staff agrees with these principles and so stated in direct testimony. (Staff Ex. 4.0, 17-18.) Staff, however, does not agree that rates for the GDS-1 customer class should be set at COSS-determined rates at this time. Staff recommends the Commission gradually work toward achieving the goal of allocating only the customer component costs determined by the COSS to the Customer Charge. (Id. at 20.)

Mr. Rubin's rate design proposal may have considerable bill impacts for certain customers, and a gradual approach will help alleviate such impacts. (Id.) Customers could see large bill impacts as a result of AIC's rate design proposal, while also facing an increase in their rates due to an overall increase to the revenue requirement. Staff's rate design proposal in comparison to AIC's results in a 19.23% to 22.08% increase for larger-use customers for distribution-only rates. (Id. at 29.) The AG's proposed rate design would result in even greater increases for distribution-only rates for larger-use customers. Staff's rate design proposal accurately balances increases for larger-use customers with an overall increase to the revenue requirement when analyzing bill impacts.

VIII. OTHER RIDER AND TARIFF CHANGES

A. Resolved/Uncontested Issues

1. Rider VBA

Staff proposed that the tariff language for the proposed Rider VBA be revised so that the annual internal audit report is submitted to the Manager of Accounting of the Commission by May 31 rather than August 1, so that the execution of the annual reconciliation proceeding is not unnecessarily delayed. (Staff Ex. 2.0, 12:221-243.) Ameren agreed to accelerate the submission of the annual VBA-related internal audit report to May 31 (Ameren Ex 23.0, 4:70-77) and reflected that change in the proposed tariff language on page 4 of Ameren Ex. 23.2.

2. Uncollectibles – Rider GUA

3. Uncollectibles – Rider S

Staff proposed an adjustment to Uncollectibles Expense based on a percentage derived from a three-year average of net write-offs of accounts receivable. (Staff Ex. 2.0, 5:91-94.) Ameren accepted Staff's methodology for the determination of the uncollectibles factor in Rider S. (Ameren Ex. 23.0, 4:64-69.)

B. Contested Issues

1. Implementation of Small Volume Transportation (SVT) Program

RESA requests that the Commission order Ameren to implement an SVT program. (ICEA/RESA Ex. 1.0, 14:282-15:297.) The Final Order in Docket No. 14-0097 makes this request moot, however. In that order, the Commission ordered Ameren to halt SVT implementation and hold workshops with all stakeholders in an attempt to fashion a cost–effective SVT program. (*Ameren Illinois Company d/b/a Ameren Illinois*, Petition for Approval of Tariffs Associated with the Small Volume Transportation Program., ICC Final Order, Docket No. 14-0097, 32-3 (July 8, 2015).)

2. Enrollment Rescission for Rider T Customers

Ameren has a uniform ten business day rescission period for all transportation customers, regardless of size, that begins when the customer switches suppliers (either from one unregulated supplier to another or from sales service to an unregulated supplier). (Ameren Ex. 19.0, 3:42-48.) Ameren witness Mr. Millburg argues that supply rescissions cancel the enrollment switch and the contract. These rescissions are required under the Act for residential and small commercial customers. Mr. Millburg distinguishes between these rescissions and enrollment rescissions that just cancel the switch-in suppliers, but do not affect the supply contract. According to Mr. Millburg, while supply rescissions apply to residential and small commercial customers under the Act, the Rider T tariff governs enrolment rescissions. (Id. at 4:66-74.)

Ameren states that it can be difficult to determine whether a customer is a small commercial customer because a customer's gas purchases can fluctuate above and below the 5,000 therm threshold year-to-year as a result of business activity or weather. Also, a customer may have several locations that together use 5,000 therms or more, even though each individual meter may read less than 5,000 therms. (Id. at 6:121-7:137; 8:150-9:174.)

The right to an enrollment rescission without a sales rescission increases risk for marketers, as a customer could exercise its right to rescind the switch after suppliers lock in the price for their gas purchases. To compensate for that risk marketers are likely to their raise bids to customers. (ICEA/RESA Ex. 1.0, 8:156-160.) In addition, customers could be liable for payments to the marketer, and ultimately pay higher costs depending on termination fees set forth in the contract. Thus, while the sales contract governs the rescission effects, the 10-day rescission period will not make gas markets more efficient for non-small commercial customers. Additionally, it has the potential to unnecessarily raise gas prices. (Staff Ex. 13.0, 5:96-101.)

Ameren witness Mr. Millburg notes that many commercial customers characterized as “non-small” may not be particularly large nor sophisticated. (Ameren Ex. 19.0, 9:185-195.) An enrollment rescission, the only remedy currently available to Rider T customers, does not offer the same level of protection as supply rescission. Moreover, the Illinois legislature did not mandate 10-business day rescission windows for non-small commercial customers. It did, however, establish a 5,000 therm threshold below which customers are governed by different rules than customers above that level. Thus, the legislature declined to provide commercial customers using more than 5,000 therms with the ability to rescind a supply contract. Staff recommends that Ameren’s tariffs be amended to withdraw the 10-business day rescission window for Rider T customers using more than 5,000 therms. (Staff Ex. 13.0, 5:106-6:116.)

3. Combined Billing Practices for Electric and Gas Customers

ICEA/RESA witness Mr. Clark asserts that, beginning in the fall of 2014, Ameren stopped sending bill data to both the electric and gas supplier as billing agent for their respective commodity. Instead, Ameren designated one supplier as the sole billing agent, and sent both gas and electric billing information to that entity. While Ameren currently applies this policy only to new customers, Mr. Clark worries that at some point Ameren will apply the policy to existing Rider T customers. (ICEA/RESA Ex. 1.0, 9:166-182.) The potential for harm, according to Mr. Clark, exists if the gas supplier is unaffiliated with the electric supplier or vice versa, so that the sole billing agent possesses the billing information for a company that may be a competitor, since many suppliers compete in both gas and electric retail markets. (Id. at 10:201-11:211.) Further, he asserts that some suppliers use their billing services to distinguish themselves from competitors. (Id. at 10:217-221.) Mr. Clark requests that the Commission order Ameren to resume allowing new customers to have billing agents for both gas and electric service separately. (Id. at 12:248-13:251.)

Ameren witness Mr. Millburg points to Ameren's gas and electric tariffs that contain the language allowing suppliers to include Ameren's delivery service charges on their bills. (Ameren Ex. 19.0, 10:214-11:219.) However, he also states that Ameren recognizes the "last authorized entity" as the Billing Agent designated by the customer, whether it supplies electricity, commodity gas or both. (Id. at 12:242-252.) Further, Mr. Millburg asserts that suppliers are able to avoid revealing competitive information by deciding how to render the bill. (Id. at 13:258-142 273.)

ICEA/RESA objects to Ameren's policy that a customer cannot choose to use single bill options for both gas and electric service and receive two bills. Ameren discusses how it determines which entity is a customer's Billing Agent, which then apparently provides a bill for both services. Mr. Clark does not, however, allege a specific violation of tariffs or ICC rules, nor does he provide suggested tariff language to remedy the problem he discusses. (Staff Ex. 13.0, 7:145-151.)

Customers should be able to choose who provides their bill. As long as the cost is not excessive, if customers want a separate bill for gas and electric service from each supplier, then customers should be able to receive two separate bills. (Staff Ex. 13.0, 8:153-155.)

4. Meter Reading and Billing Practices for Rider T Customers

ICEA/RESA complains that Ameren is not providing bills to suppliers in a timely fashion. It wants Ameren to provide the information more quickly to allow suppliers to bill their customers more quickly and decrease the volume of amended bills. (ICEA/RESA Ex. 1.0, 13:252-14:280.) It is not clear, however, what relief ICEA/RESA is requesting. It makes no assertions concerning how prevalent the problem is and gives no indication of the extent to which suppliers have tried to resolve this issue with Ameren before this rate case was initiated. Further, ICEA/RESA does not allege that Ameren has violated its tariffs, contracts with suppliers, Commission rules or Illinois law. Therefore, this dispute is not ripe for a Commission ruling. (Staff Ex.13.0, 8:170-9:176.)

IX. OTHER ISSUES

A. Resolved/Uncontested

1. General Services Agreement Allocators

B. Contested Issues

1. Forecasted FERC Account Data

X. CONCLUSION

Staff respectfully requests the Illinois Commerce Commission approve its recommendations in this docket.

Respectfully submitted,

/s/

JIM OLIVERO
KELLY A. TURNER
MARCY SHERRILL

Illinois Commerce Commission
Office of General Counsel
160 North LaSalle Street, C-800
Chicago, IL 60601
(312) 793-2877
jolivero@icc.illinois.gov
kturner@icc.illinois.gov
msherrill@icc.illinois.gov

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Counsel for Staff of the Illinois Commerce Commission