COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT OF ITS	**)**	**CASE NO. 2016-00370**
ELECTRIC RATES AND CERTIFICATES	**)**	
OF PUBLIC CONVENIENCE AND	**)**	
NECESSITY	**)**	

In the Matter of:

APPLICATION OF LOUISVILLE GAS	**)**	
AND ELECTRIC COMPANY FOR AN	**)**	
ADJUSTMENT OF ITS ELECTRIC AND	**)**	**CASE NO. 2016-00371**
GAS RATES AND CERTIFICATES OF	**)**	
PUBLIC CONVENIENCE AND NECESSITY	**)**	

REBUTTAL TESTIMONY OF
KENT W. BLAKE
CHIEF FINANCIAL OFFICER
LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Filed: April 10, 2017

Q. Please state your name, position and business address.

A. My name is Kent W. Blake. I am the Chief Financial Officer of Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies"), and an employee of LG&E and KU Services Company, which provides services to LG&E and KU. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut intervenor testimony on the issues of: (1) use of a forward-looking test year; (2) incentive compensation; (3) "slippage" on capital expenditures; and (4) workforce headcount issues.

Forward-Looking Test Year Considerations

Q. Do you have any comments on KIUC witness Mr. Kollen's contention that the Companies' use of a forward-looking test period requires the Commission to review the Companies' proposals in this case with "healthy skepticism" and that utilities using a forward-looking test period are incentivized to "overstate" their costs?[1]

A. Yes. We take this disappointing allegation very seriously and deny it emphatically. The Commission has carefully evaluated the Companies' applications in the past and will no doubt do so again in the present cases, but it is inappropriate and unnecessary to review these cases with any sort of additional skepticism, suspicion, cynical criticism or any other sort of negative connotation. As demonstrated in great detail by the Companies' Applications, direct testimony, responses to data requests, and

[1] See Mr. Kollen's testimony filed on behalf of KIUC, pp. 5-6.

rebuttal testimony, the Companies have carefully considered, analyzed and presented each and every aspect and proposal in these base rate cases in a manner worthy of this Commission's unbiased review.

The General Assembly authorized utilities to file base rate cases based on a forward-looking test period 25 years ago.[2] Since that time, the Commission has gained an enormous amount of experience handling forward-looking test period cases because most major utilities subject to the Commission's jurisdiction file cases based on forward-looking test years. There is no doubt that the Commission is fully capable of assessing the reasonableness of the Companies' evidence supporting their requests.

As attested by Mr. Staffieri pursuant to 807 KAR 5:001 Section 16 (7) (e) in the Companies' Applications in this case, the financial forecasts used in this case are the same financial forecasts prepared for use by management of the Companies and were made in good faith. In fact, those forecasts were prepared with the knowledge that they would not only be used to set objectives and market expectations, but also be used to support the Companies' Applications to establish retail base rates in Kentucky. The Companies have submitted extensive evidence showing not only their estimated budgets for the test period, but detailed explanations and documents supporting their business processes for developing the budget estimates. The Companies have responded to nearly 5,200 requests for information, counting subparts, from the Commission and intervening parties in this case on almost every conceivable issue or topic raised by the Applications. There can be no legitimate

[2] KRS 278.192 states, in part, "For purposes of justifying the reasonableness of a proposed general increase in rates, the commission shall allow a utility to utilize . . . a forward-looking test period . . ."

question raised about the motives of the Companies' financial forecasts or the financial forecasting processes with this kind of transparency.

Contrary to the unsupported suggestion by Mr. Kollen that the Companies' proposals in this case are "overstated," the detailed explanations of the Companies' bottom-up approach to budgeting demonstrates the reasonableness of the estimates and confirm that the core values of operating efficiently and controlling costs to the extent practicable are embedded in our organization. And there is conclusive proof that the Companies do not overstate financial projections to inflate rates. The Companies' 2014 rate cases were their first based on forward-looking test periods. Thus, forward-looking looking information was filed in those cases for the forward-looking test period upon which rates were set (which was July 1, 2015 to June 30, 2016), but we also filed the projected 2018 operating expenses. In the Companies' 2014 rate cases, the projected 2018 operating expense for the expense items over which we have the most control, "Other Operating Expenses" and "Maintenance," totaled $498 million for KU[3] and $415 million for LG&E.[4]

Now, in the current cases, we have filed the Companies' most current projections which includes projected operating expenses for 2018. The combined projected operating expenses for "Other Operating Expenses" and "Maintenance" for 2018 are actually *lower* than what we projected in our 2014 rate cases. For KU for

[3] See Tab 61 to KU's Application in Case No. 2014-00371 showing "Other Operating Expenses" for 2018 of $347 million and "Maintenance" for 2018 of $151 million for a total of $498 million.
[4] See Tab 61 to LG&E's Application in Case No. 2014-00372 showing "Other Operating Expenses" for 2018 of $301 million and "Maintenance" for 2018 of $114 million for a total of $415 million.

2018, the projection is $480 million[5] (for a reduction of $18 million) and for LG&E for 2018, the projection is $387 million[6] (for a reduction of $28 million).

Although "Other Operating Expenses" and "Maintenance" are the expense items over which we have the most control and "Total Operating Expenses" includes expense items such as fuel expense over which we have less control, a comparison of projected Total Operating Expenses for 2018 tells the same expense reduction story. In the Companies' 2014 rate cases, the projected 2018 Total Operating Expenses for KU was $1.678 billion.[7] Likewise, the projected 2018 Total Operating Expenses for LG&E was $1.420 billion.[8] In the current cases, the projected 2018 Total Operating Expense for KU is $1.545 billion[9] and the projected 2018 Total Operating Expense for LG&E is $1.273 billion.[10]

The forward-looking test period upon which rates will be set in this case is July 1, 2017 to June 30, 2018, and the Companies have actually *lowered* their projected operating expenses for the critical time period in question relative to the projections made in the 2014 rate cases. Furthermore, that decrease has occurred even with operating expense additions (that were not in the 2014 rate cases) that will result from important customer service and reliability programs we now know are needed such as our Distribution Automation and Automatic Metering System proposals. Further proof of our hard work to control costs so that rates are kept as

[5] See Tab 62 to KU's Application in this case showing "Other Operating Expenses" for 2018 of $320 million and "Maintenance" for 2018 of $160 million for a total of $480 million.
[6] See Tab 62 to LG&E's Application in this case showing "Other Operating Expenses" for 2018 of $270 million and "Maintenance" for 2018 of $117 million for a total of $387 million.
[7] See Tab 61 to KU's Application in Case No. 2014-00371.
[8] See Tab 61 to LG&E Application in Case No. 2014-00372.
[9] See Tab 62 to KU's Application in this case.
[10] See Tab 62 to LG&E Application in this case.

low as possible is included in Exhibit KWB-1 to my direct testimony. That exhibit summarizes the most recent electric utility operating cost benchmark study which shows that LG&E and KU are below the industry average cost in all areas of the comparison, and are in the top quartile in the areas of Generation, Transmission, Distribution, and Customer Service.

Additionally, as explained in my direct testimony, our forecasts in the Companies' 2014 rate cases were very accurate when compared to the actual results experienced and we have made some adjustments to our labor forecasting in an effort to make our forecasting even more accurate.[11] All of this proves three things: (1) we do not and have not overstated financial projections to inflate rates; (2) we have worked very hard at cost control, which, as set forth below, is one of the objectives of our incentive compensation program; and (3) there is no call for any bias or added "skepticism" in reviewing these cases simply because they are based on forward-looking test periods.

<u>Team Incentive Award and Incentive Compensation</u>

Q. Please describe the Companies' Team Incentive Award ("TIA") Plan.

A. The TIA Plan is a long-standing "at risk" pay program[12] in which a part of an employee's annual cash compensation is put at risk and objectives are established for the employee. If certain performance results are achieved, a cash incentive award will be earned. The actual amount of the award depends upon the achieved results.

[11] See my direct testimony, pp. 13-14.

[12] A copy of the TIA Plan was attached to AG 1-210 in Case No. 2016-00370 (KU) and AG 1-210 in Case No. 2016-00371 (LG&E) and is also attached hereto as Rebuttal Exhibit KWB-1. A copy of correspondence provided to employees notifying them of the 2017 TIA measures and weightings is attached as Rebuttal Exhibit KWB-2.

The TIA Plan, which has been in place since the 1990s, was developed to motivate, focus and direct employees toward the achievement of strategic goals and is part of an overall corporate strategy to attract and retain skilled employees by providing competitive financial awards that are commensurate with the employees' talents, cooperation, and contribution. It is intended to motivate participants to achieve higher levels of performance, communicate and focus on critical success measures, reinforce desired behaviors, and bolster an employee ownership culture.

Q. Have you reviewed the intervenor testimony regarding the recoverability of incentive compensation under the TIA Plan?

A. Yes. I reviewed Mr. Smith's testimony filed on behalf of the AG in which he recommends a 25% reduction in the amount of incentive compensation the Companies have requested in these proceedings. The amount of Mr. Smith's proposed reduction is $2.605 million out of the $10.42 million KU has requested and $2.717 million ($2.044 million for electric and $.673 million for gas) out of the $10.867 million LG&E has requested.[13] I have also reviewed Mr. Pollock's testimony filed on behalf of the Kentucky League of Cities ("KLC") in the KU case and Louisville Metro in the LG&E case in which he recommends similar reductions to incentive compensation expense.[14,15] No other intervenor has proposed a disallowance of incentive compensation expense and although the AG, KLC, and Louisville Metro propose only a partial disallowance, those proposals have no merit.

[13] Smith Testimony, pp. 22-31 (KU) and pp. 27-36 (LG&E).
[14] Pollock Testimony, pp. 21-26 (KU) and pp. 24-30 (LG&E). The exact amounts of Mr. Pollock's recommended reductions were filed confidentially.
[15] Mr. Pollock is mistaken when he states that the requested amount of incentive compensation expense for KU is $11.5 million. As Mr. Smith points out at p. 24 of his testimony in the KU case, the amount of jurisdictional incentive compensation expense requested is $10.42 million as set forth in KU's response to Kroger 2-3.

Q. Do you agree with those recommendations?

A. No. The Companies' incentive compensation expense is reasonable and it should be recovered in full for several reasons. First, the Companies have proven that the total compensation paid to employees, which includes both base salary *and* incentive compensation, is reasonable and consistent in the competitive marketplace.[16] Without incentive compensation, the compensation paid would fall below market rates and hinder the Companies' ability to attract and retain a qualified workforce. Second, the Companies have proven that the relative mix of base salaries and incentive compensation in determining overall cash compensation is reasonable and at a competitive level when compared to the competitive marketplace.[17] In other words, the amount of incentive compensation offered is consistent with the marketplace levels.

Third and finally, as described below, the Companies have modified the measures and weightings for their TIA Plan in recent years to eliminate any connection to the Companies' financial performance. Thus, to the extent the Commission has disallowed incentive compensation expense for utilities in the past because it has been tied to a utility's financial performance (such as earnings per share or net income), those past decisions have no bearing on the Companies' current TIA Plan because, while the TIA Plan once included those connections, it no longer does.

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[16] See the Willis Towers Watson study discussed in more detail below.
[17] See the Willis Towers Watson study discussed in more detail below.

Q. How have the Companies ensured and proven that the total compensation paid to employees is reasonable and at competitive market rates?

A. The annual process of setting compensation includes reliance on benchmarking information[18] in calibrating the level of the primary components of compensation.[19] Various third-party benchmarking and salary planning surveys from the energy services and general industries categories are utilized. The 50th percentile is used to establish the market midpoint of annual total compensation ranges which include incentive compensation. Compensation is then managed based on various factors including education, experience, performance, time in job, and tenure.

In addition to the internal compensation setting process described above, when the Companies filed their Applications, they submitted a study[20] that was performed by Willis Towers Watson ("WTW") in November, 2016.[21]

Q. Who is Willis Towers Watson?

A. WTW is a global consulting company that provides an array of services to businesses. WTW advises organizations on all aspects of their compensation programs with the goal of paying employees appropriately and enabling organizations to attract, retain and motivate employees efficiently and cost-effectively. Typical areas of compensation consulting assistance include pay philosophy development, variable or at-risk compensation plan design, total compensation benchmarking, and compensation structure development.

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[18] For a listing of the compensation surveys we use, see PSC 1-35 in both cases.
[19] See also the Company's response to PSC 1-55 in both cases.
[20] The study is the sort of study described by the Commission at p. 15 of its September 15, 2016 Order in *In the Matter of: Application of Kenergy Corp. for a General Adjustment in Rates*, Case No. 2015-00312.
[21] See Tab 60 to the Companies' Applications for a complete copy of the WTW report.

Q. Please describe the WTW study the Companies submitted.

A. For the study, WTW reviewed the Companies' Target Total Cash Compensation (which includes salary and target incentive compensation levels under the TIA Plan) in comparison to benchmarking data to determine the reasonableness of the Companies' compensation levels. WTW concluded the following:

- When compared to available published survey data, LG&E's and KU's projected and actual base salary budgets are generally aligned with market median levels;

- Competitiveness of target total cash compensation: LG&E's and KU's use of base salary and target short-term at-risk compensation as its primary pay vehicles for employees is consistent and aligned with market pay vehicles used by utility and general industry peers. Likewise, when compared to available published survey data, LG&E's and KU's compensation levels fall within the competitive range of the market 50th percentile for base salary and target total cash compensation (Target TCC = base salary + target short-term at-risk compensation);

- When compared to available published survey data, LG&E's and KU's pay mix (base salary and target short-term at-risk compensation) generally places less emphasis on short-term at-risk compensation than peers, but approximates market practice overall.

The WTW report confirms that our compensation setting philosophy and process has resulted in exactly what we strive to achieve -- that with the inclusion of incentive compensation, our compensation levels are very closely aligned with market medians. And the converse is also true in that if incentive compensation is eliminated from total compensation, the Companies' compensation levels would fall below market and therefore jeopardize our ability to attract and retain an adequate workforce.

Q. How are TIAs determined?

A. All eligible employees have a TIA target award. The criteria for and calculation of those awards for 2017 are set forth in the TIA Plan. As set forth in that document, the 2017 target awards are:

Employee Status	Target Award
Non-Exempt and Hourly/Bargaining Unit	6% of Annual Earnings
Exempt Individual Contributors	9% of Base Salary
Managers	14% of Base Salary
Senior Managers	25% of Base Salary

For an individual employee in 2017, as reflected in the Companies' response to AG 1-210 and communicated to employees as shown in Rebuttal Exhibit KWB-2, the calculation of incentive compensation is determined using the following objectives and percentages: (1) corporate safety (15%); (2) customer satisfaction (15%); (3) cost control (15%); (4) customer reliability (15%); and (5) individual/team effectiveness (40%).[22]

Q. Please describe the performance objectives of corporate safety, customer satisfaction, cost control, customer reliability, and individual and team effectiveness.

A. The following is a description of each objective provided in response to discovery requests:[23]

- Corporate Safety is measured by using recordable injury rates, illness rates, and "days away, restricted and transfer" rates, commonly referred to as "DART" rates.
- Customer Satisfaction is measured by the Company's performance ranking within its peer group. The Company's market research vendor contacts randomly selected Company customers and customers from peer group companies and asks them about overall satisfaction with their respective utilities.

[22] See Rebuttal Exhibit KWB-1 at p. 4 and Rebuttal Exhibit KWB-2 at pp. 1-2.
[23] See also the responses to KLC 2-19 (KU) and Louisville Metro 2-17 (LG&E).

- Cost Control is measured by non-fuel operation and maintenance expenses in accordance with generally accepted accounting principles as published in the Companies' annual Form 10-K filings with the Securities and Exchange Commission.
- Customer Reliability is measured by the System Average Interruption Duration Index ("SAIDI") which is a well-known industry metric for service reliability.
- Individual and Team Effectiveness measures ensure that employees are collectively working to achieve strategic business goals. Individual goals will vary by the individual employee and by department. They support respective department and line of business objectives.

As one can see, the objectives are designed and implemented to serve customers interests above all else. The four company objectives are directly aligned with the Companies' mission "to provide ***reliable***, ***safe*** energy at a reasonable ***cost*** to our ***customers*** . . . ."[24](emphasis added).

Q. Are there any financial targets or measures that must be met before any incentive pay can be awarded or that factor into an individual employee's TIA award?

A. No. There is no connection or "trigger" between earnings and the availability of awards under the TIA Plan. Additionally, as recently as 2016, which is included in the Companies' base year in this case, the calculation of an individual employee's award was based, in part, on levels of Net Income achieved by the Companies. However, as reflected in the 2017 TIA Plan employee communication,[25] Net Income is no longer a factor in calculating the award. It has instead been replaced by the operating criteria of corporate safety, cost control, and customer reliability with corporate safety added in 2016 and the other two added in 2017. Prior to that, these

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[24] https://lge-ku.com/our-company/vision-mission
[25] See Rebuttal Exhibit KWB-2.

metrics were only included in the Individual and Team Effectiveness measures of certain employees. Despite Mr. Pollock's claim that Net Income is still "implicit" in the criteria, that is simply not the case and contrary to the evidence in the record.

The Companies have reviewed and considered Commission decisions that disallow some or all incentive compensation when it is tied to financial goals. While the Companies do not necessarily agree with the concept that incentive compensation that is tied to financial goals should not be recovered in rates, the Companies have altered the measures used in their TIA Plan and removed financial performance metrics such as net income or earnings per share. In doing so, the TIA Plan is now squarely aligned with the Commission's directive that incentive compensation should be directly tied to customer benefits and includes metrics that are more directly controlled by affected employees.

Q. Then do you find Messrs. Smith's and Pollock's reliance on previous Commission decisions disallowing some level of incentive compensation misplaced?

A. Yes. Messrs. Smith and Pollock both rely on Commission decisions disallowing some level of incentive compensation when that incentive compensation is tied to the earnings per share of the utility (or its parent) or to the financial performance of the utility. The TIA Plan has no such focus or feature, so any reliance on those decisions is erroneous.

Q. Do you agree with Messrs. Smith and Pollock that incentive compensation in the future test period is excessive and still tied to financial performance?

A. No. As set forth above, the Companies have provided a third-party assessment that its incentive compensation is not excessive and have demonstrated that incentive compensation under the TIA program is not tied to the Companies' or their parent company's financial performance. As shown by the chart below, projected incentive compensation in the test year is also very consistent with actual results of the base period.

Description	*KU*	*LG&E (gas & electric)*
TIA Plan Payments During Base Period (Updated with Actuals)	$11.078 million	$10.444 million
100% of TIA Plan Payments in Forecasted Test Period as Requested in Proposed Rates	$10.42 million	$10.867 million
Difference – Increase/(Decrease)	($.658 million)	$0.423 million

Under Kentucky law, a utility is entitled to rates that permit the recovery of reasonable expenses incurred to provide service. While the Commission may and should disallow a utility's unreasonable expenses, the Companies have shown that their philosophy in setting total compensation, which includes incentive compensation, is consistent with the competitive marketplace. It has also shown that its TIA Plan awards incentive compensation in ways that benefit customers above all else. Therefore, all of the requested incentive compensation expense should be included in rates.

<u>“Slippage” Related to Capital Expenditures</u>

Q. Do the Companies believe that a “slippage factor” should be applied to their forward-looking test period capital projects as suggested by AG witness Mr. Smith and KIUC witness Mr. Kollen?

A. No. As the Companies have explained in their discovery responses, the calculated capital construction slippage factors (97.204 percent for KU and 98.111 percent for LG&E) demonstrate their accuracy in predicting the cost of utility plant. This accuracy has been achieved through use of a very robust process for forecasting capital expenditures and managing to that forecast. Given these high degrees of accuracy, the need to apply a slippage factor does not exist and the Commission should decline to do so.

Q. Are there any potential adverse consequences from imposing a “slippage factor” to projected capital construction in a forward-looking test period rate case?

A. Yes. If a purely numeric slippage factor calculation based on historic results is used to either reduce or increase the projected capital construction costs, it can provide a disincentive for utilities to continue their efforts to reduce capital costs after having established its annual budget. In forward-looking test period rate cases, a utility is required to provide their actual forecast for capital spend “made in good faith.” If a utility has historically been successful in managing down capital cost estimates, it would not be allowed to recover its then best estimate of capital spend for its forward-looking test period. In contrast, a utility that has been less effective in managing to or below its costs estimates and has incurred significant overruns on capital projects would actually be rewarded by being provided a revenue requirement above its best estimate of capital construction costs.

Q. Are the Companies aware of instances in which the Commission has not applied a "slippage factor" to projected capital construction in a forward-looking test period rate case?

A. Yes. Contrary to the suggestion in Messrs. Smith's and Kollen's testimony, Commission precedent does not require "slippage factor adjustments" to projected capital expenditure in all forward-looking test period rate cases. In fact, with the exception of rate proceedings involving Kentucky-American Water Company ("KAWC"),[26] the Commission appears to have applied a slippage adjustment factor in only one other proceeding.[27] Since that decision, which was entered nearly twelve years ago, the Commission has *not* applied a slippage adjustment factor in any non-KAWC forward-looking test period proceeding. The table below lists the forward-looking test period rate cases since 2006 in which the Commission made specific findings regarding rate base or capital expenditures and each applicant's reported slippage factor.[28]

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[26] The Commission's treatment of KAWC appears to be based upon historic concerns regarding that utility's budgeting process. *See, e.g.*, Case No. 95-554, *Application of Kentucky-American Water Company to Increase Its Rates* (Ky. PSC Nov. 19, 1993) at 3 ("Based on the historical relationship demonstrated by the slippage factor, the Commission concluded Kentucky-American's "very best estimate(s)" of construction spending was inaccurate and showed a pervasive pattern of over budgeting for construction. To eliminate Kentucky-American's historical overestimation, the Commission reduced the forecasted recurring and specific budget projects by their respective slippage factors."

[27] Case No. 2005-00042, *An Adjustment of the Gas Rates of Union Heat, Light and Power Company* (Ky. PSC Dec. 22, 2005).

[28] Since its decision in Case No. 2005-00042, the PSC has considered at least thirteen non-KAWC forward-looking test period applications. The nine cases that are not listed were resolved through unanimous settlement agreements. Accordingly, the Commission was not required to address rate base or capital expenditures.

Case Number	Utility	Utility's Calculated Average Slippage Factor[29]	Date of Order
2010-00167	East Kentucky Power Coop.	81.396	01/14/2011
2012-00535	Big Rivers Electric Corp.	102.581	10/29/2013
2013-00148	Atmos Energy Gas	105.442	04/22/2014
2013-00199	Big Rivers Electric Corp.	95.790	04/25/2014

KU's and LG&E's slippage factors, which are 97.204[30] percent and 98.111[31] percent, compare very favorably to those listed above.[32] Given this greater accuracy and the Commission's decision not to apply a slippage factor in the listed cases, it is clear that Commission precedent does not support the application of a slippage factor adjustment in the current proceedings. Mr. Smith also argues that his slippage adjustment flows through to the Companies' capitalization and depreciation expense. As the slippage adjustment itself should not apply, those suggested flow-throughs are not applicable and should be disregarded.

Headcount and Workforce Level Issues

Q. Do you agree with Mr. Smith's testimony on behalf of the AG that the Companies should not be allowed to recover the labor expense associated with positions they plan to fill by the end of the forecasted test year?

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[29] These factors are based upon a ten-year average except for Big Rivers Electric Corporation, which lacked sufficient information to develop a ten-year average slippage factor and provided a factor based upon the available information.

[30] See KU's response to Staff 1-13.

[31] See LG&E's response to Staff 1-13.

[32] The Companies' slippage factor also compares favorably to that of Union Light, Heat and Power Company ("ULH&P") in Case No. 2005-00042. In that proceeding, which involved a request for adjustment of gas rates, ULH&P reported a slippage factor of 97.045 percent for its gas operations and 100.6 percent for its electric operations. *See* Case No. 2005-00042, Order of Dec. 22, 1994 at 9.

A. No. Mr. Smith's arguments on this issue are in the alternative. First, he argues that KU has proposed four "additional" positions, LG&E has proposed 22 "additional" positions, and 34 "additional" positions are proposed for LG&E and KU Services Company ("LKS").[33] He goes on to argue that recovery for those "additional" positions should not be permitted because the Companies have failed to demonstrate "that those additional positions are needed and/or would be filled for the full duration of the forecasted test year." Mr. Smith then alternatively argues that should the Commission allow rate recovery for those requested "additional" positions, it should still disallow a portion of labor expense based on the fact that, at any given point in time, a company, including a utility, will have some unfilled vacant positions due to employee turnover as reflected in actual vs. budgeted labor expense.

Q. Do you agree that "additional" positions have been proposed?

A. No. Mr. Smith confuses "vacant" positions with "additional" positions. It appears that Mr. Smith has incorrectly interpreted KU's responses to AG 1-49 and AG 2-8 and LG&E's responses to AG 1-49 and AG 2-8 to mean that the Companies are proposing incremental *additions* to its workforce in this case. They are not. As explained in those responses, the four KU positions, 22 LG&E positions, and 34 LKS positions are simply the positions that happened to be vacant on December 31, 2016. The Companies are not "adding" that number of positions in the forward-looking test period. The direct testimony of Mr. Thompson and Mr. Bellar addressed the operational headcount additions in this case relative the Companies' prior rate case

[33] Smith testimony at p. 42 (KU) and p. 47 (LG&E).

and my direct testimony actually noted a reduction of financial and administrative positions between cases.

Q. Have the Companies demonstrated a need for their overall workforce levels?

A. Yes. The Companies have submitted and supported their employment forecasts. Mr. Smith did not specify any legitimate reason or critique of the actual employment forecast or the process by which that forecast is made. His only argument is the unsupported statement that the Companies have not demonstrated a need for the positions that happened to be vacant on December 31, 2016. In doing so, Mr. Smith ignores evidence in the record demonstrating the procedures followed in determining employment forecasts which lead to a reliable and appropriately staffed workforce.

The development of the workforce begins with the Companies' September 1, 2016 Workforce Plan[34] ("WFP"). The WFP is an exhaustive document that considers every aspect of the workforce including its level, age, overtime, training, retention and use of contractors.[35] Staffing levels are based on discussions between staff and senior executives with consideration to realignments to the previous year's staffing level based on changes in workload, needs of the organization, and changes in personnel.[36] The WFP process is intensive and leads to the following benefits: more effective and efficient use of workers; ready availability of replacements when vacancies are created; resources to aid in establishing the business plan; a clear

[34] A copy of the WFP is attached to LG&E's response to AG 1-59.
[35] WFP, p. 4.
[36] WFP, p. 3.

rationale for making expenditures for training, retraining, employee development, career counseling, and recruiting efforts; and a diverse workforce.[37]

In the WFP process, the Companies examine whether they: can eliminate, change, or subcontract work; have a need for the work to be performed in-house; can achieve any efficiencies not already being achieved; can reconfigure positions or responsibilities to avoid headcount additions; and have identified employees with critical knowledge whose knowledge needs to be transferred as part of a succession plan.[38] In other words, the WFP process is an extremely robust process that ensures a highly efficient and lean workforce that can provide adequate service both now and in the future. It is this process that has led the Companies to show very modest incremental headcount numbers for the forward-looking test period. Additionally, Mr. Bellar's direct testimony describes the unique staffing needs for LG&E's gas operations driven by the need to comply with existing and new regulatory requirements (including gas pipeline safety requirements) and the looming retirements of certain gas personnel.[39] By 2021, almost 40% of LG&E front-line gas operating employees will have 35 or more years of experience. Proactive measures need to be taken before those retirements occur to ensure an efficient transfer of the critical knowledge held by retiring employees and to allow time for employees to complete required training and certifications. It is only prudent to do so.

Q. As for Mr. Smith's alternative argument regarding employment vacancies, are you aware of any prior Commission Orders in forward-looking test period rate

[37] WFP, p. 3.
[38] WFP, p. 1.
[39] Mr. Bellar's direct testimony, pp. 7-10.

cases in which the Commission has addressed the issues of adjusting a utility's labor forecast for assumed vacancies?

A. Yes. The Commission previously rejected the exact type of argument Mr. Smith has made in these proceedings for a disallowance of labor expense based on a historical vacancy rate.[40] In fact, in one of those cases (Case No. 2010-00136), Mr. Smith was the AG witness who proposed that disallowance. There, as here, Mr. Smith failed to consider the vacancies' effect on other costs such as overtime and contract labor forecasts. The Commission rejected his argument there and should reject it in these proceedings as well.

Q. Did you address this exact vacancy issue in your direct testimony?

A. Yes. At page 9 of my direct testimony, I explained the process by which we considered the effect of vacancies in our labor forecast expense proposed in these cases. First, we eliminated 20 positions from the forecast because they had been vacant for a long enough period to conclude they would not be filled. For the remaining vacancies, we concluded that the work would have to be performed by either filling the vacant positions or by spending additional funds on contractors, overtime, and premium pay. Thus, there is an inverse relationship between vacancy levels on the one hand and contractor, overtime, and premium pay expense on the other hand. This is why Companies did not embed some sort of vacancy rate "discount" in their labor forecasts due to turnover. At bottom, there is a certain

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[40] *See In the Matter of: Application of Kentucky-American Water Company to Increase its Rates,* Case No. 1995-00554, Order at 32 (Sept. 11, 1996); *In the Matter of: Adjustment of the Rates of Kentucky-American Water Company,* Case No. 2004-00103, Order at 45 (Feb. 28, 2005); *In the Matter of: Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year,* Case No. 2010-00036, Order at 25 (Dec. 14, 2010).

amount of work the Companies must perform either by a full workforce or by additional contractor, overtime, and premium pay expense – and this is the precise concept the Commission relied upon in rejecting Mr. Smith's vacancy adjustment in Case No. 2010-00036.

Q. So do the Companies agree with Mr. Smith's alternative argument that a reduction in labor expense should be applied based on an historical variance between budget-to-actual for labor expense?

A. No. The Companies did not explicitly subtract vacancies caused by employee turnover into their headcount forecast. To do so would create a budget with management challenges. For example, if a department with 100 employees had a historical vacancy rate of 2%, a budget adjusted for this vacancy rate in effect allows that department manager only 98 approved positions - notwithstanding that all 100 positions in the Companies' headcount forecast have been approved as part of the business plan based on a demonstrated need for 100 employees. To suggest an adjustment based on historic deviations from budget in this one variable overlooks the fact that the work of the 100 budgeted employees still must be accomplished.

Q. Have the Companies had an historical variance between actual and budgeted employee headcount?

A. Yes. However, absent a change in the amount of work to be performed, any reduction in employee headcount has been offset by incremental overtime, incremental use of outside contractors or an increase in the backlog of work to be performed. This, of course, is not surprising given that a certain amount of work must be performed and if we do not have a position filled to do that work due to a vacancy created by turnover, it must be performed by relying on overtime of existing employees or outside contractors. Additionally, the Companies have explained that the primary reason for vacancies at any point in time is normal employee turnover and attrition.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Kent W. Blake**, being duly sworn, deposes and says that he is Chief Financial Officer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Kent W Blake

Kent W. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of April 2017.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2018

Rebuttal Exhibit KWB-1

Team Incentive Award (TIA) Plan

TEAM INCENTIVE AWARD (TIA) PLAN

- Corporate Safety
- Customer Satisfaction
- Cost Control
- Customer Reliability
- Individual and Team Effectiveness

TIA

Eligible employees participate in the LG&E and KU Team Incentive Award ("TIA"). The TIA focuses employee efforts on customer and business goals and rewards employees for achieving those goals. The TIA provides an opportunity for eligible employees to share in the added value they create through superior performance.

TIA AND BUSINESS STRATEGY

The company realizes the wealth that exists in the abilities of its people. The challenge is to become the best in our competitive market through each individual using his or her talents combined with other team members to make it happen. The TIA Plan plays a key role in assisting the company in focusing employees on customer and business goals as well as providing employees with a program that can increase their individual compensation.

The TIA was developed to motivate and direct employees toward the achievement of strategic goals. It also assists with attracting and retaining skilled personnel by providing competitive compensation commensurate with their talents, cooperation and contribution.

There are several basic TIA concepts:

- There is a focus on the cooperative spirit of all employees working together as a team.
- Risk-taking, embodied in initiative, fresh perspectives and innovative solutions, is encouraged and rewarded.
- The plan is designed to motivate and improve the individual performance of all employees.
- Incentive award levels vary depending on the employee's base salary, position and performance. The TIA represents "pay at risk." The relationship of the target awards to salary reflects that employees who have increasing responsibility for customer and business performance, as reflected in higher salaries, generally have higher amounts of individual compensation tied to that performance.

With these concepts in mind, the TIA was designed:

- To promote the achievement of the company's objectives.
- To attract, motivate and retain employees.

TIA PLAN

Key elements of the TIA are as follows:

1. Participants include all active full-time and regular, part-time salaried employees, IBEW 2100 employees and KU hourly and bargaining unit employees.

2. All TIA participants have Target Awards based on the following:

Target Award Participation

Non-Exempt & Hourly	6% of annual earnings
Exempt Individual Contributors	9% of base salary
Managers	14% of base salary
Senior Managers	25% of base salary

3. Performance objectives are established annually to support the customer and business strategies. The size of the awards depend upon the degree to which these objectives are achieved.

4. Exempt employees with salary changes during the year will have their awards calculated in accordance with the amount of time they work under each respective base salary.

5. Total annual earnings, including overtime, are used in calculating the earned awards for all regular non-exempt and hourly full- and part-time employees. Prior TIA awards are excluded from total annual earnings to calculate earned awards.

6. Earned TIA Awards will be paid in cash within 90 days of the completion of the calendar-based annual performance period.

7. Compensation from the TIA is included in calculating benefits under the Company's Retirement (except for the KU Retirement Plan) and 401(k) Savings Plan.

8. This plan in no way creates a contract of employment for any duration. The company has full and final discretion with respect to the interpretation and application of this plan. The Company reserves the right to modify or terminate this plan in its sole discretion. This plan document supersedes any prior plan document relating to the TIA.

ELIGIBILITY

All active, regular full- and part-time salaried employees, IBEW 2100 employees and KU hourly and bargaining unit employees, who have at least one month continuous service and are on the payroll on December 31 of the performance year, are eligible for a TIA. Employees who become disabled, die or retire during the performance year will be eligible for a prorated award. Disability, for purpose of this plan, means that the employee is eligible for the receipt of benefits under the Long Term Disability Plan. Retire means that the employee is eligible to retire under the terms of a company sponsored retirement plan. Employees who join the company during the performance year, who have at least one month continuous service, and are on the payroll on December 31 will also be eligible for a prorated award. Employees incurring unpaid work days during the performance year may experience a proportionate reduction in their TIA.

INDIVIDUAL PERFORMANCE OBJECTIVES

The individual performance objective links individual performance to the TIA award. The individual performance objective can be combined with performance objectives for small teams as well as with key objectives from the Performance Excellence Process. Individual performance objectives should align with, and support, strategic customer and business goals to drive performance.

TIA COMMUNICATION

TIA performance results for customer, business and operational performance measures are communicated through the Company's internal communications to provide information concerning performance. Final TIA performance results are approved following the completion of the performance period and are communicated through the Company's internal communications.

CONCLUSION

The Team Incentive Award Plan is designed to strengthen the connection between pay and performance. It will direct a portion of total pay to awards based on customer, business, operational and individual achievements. The TIA focuses eligible salaried and hourly employees' attention on the company's business goals.

TIA FORMULA

The TIA calculation formula is shown below, along with an example of a potential award. In this example, note the participant's salary is $40,000 and the target award is 9%.

TIA CALCULATION

Step 1: Target Award % x Annual Base Pay Earnings = Target Award

Step 2: Target Award x Corporate Safety Weighting x Performance % = Corporate Safety Award

Step 3: Target Award x Customer Satisfaction Weighting x Performance % = Customer Satisfaction Award

Step 4: Target Award x Cost Control Weighting x Performance % = Cost Control Award

Step 5: Target Award x Customer Reliability Weighting x Performance % = Customer Reliability Award

Step 6: Target Award x Individual or Team Weighting x Performance % = Individual or Team Award

Step 7: Corporate Safety Award + Customer Satisfaction Award + Cost Control Award + Customer Reliability Award + Individual or Team Award = Total TIA Award

TIA CALCULATION EXAMPLE

Annual Base Pay Earnings = $40,000
Target Award Percent = 9%
Corporate Safety Performance % = 105%
Customer Satisfaction Performance % = 110%
Cost Control Performance % = 100%
Customer Reliability Performance = 110%
Individual or Team Performance % = 105%

Step 1: 9% x $40,000 = $3,600 Total Award

Step 2: $3,600 x 15% x 105% = $567 Corporate Safety Award

Step 3: $3,600 x 15% x 110% = $594 Customer Satisfaction Award

Step 4: $3,600 x 15% x 100% = $540 Cost Control Award

Step 5: $3,600 x 15% x 110% = $594 Customer Reliability Award

Step 6: $3,600 x 40% x 105% = $1,512 Individual or Team Award

Step 7: $567 + $594 + $540 + $594 + 1,512 = $3,807 Total TIA Award

Rebuttal Exhibit KWB-2

2017 Team Incentive Award measures, weightings announced

PPL companies

Employee Bulletin

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January 24, 2017

2017 Team Incentive Award measures, weightings announced

Cost control and customer reliability measures replace net income.

LG&E and KU's Team Incentive Award (TIA) is a core component of the company's compensation. Last year, the TIA included measures for Net Income, Customer Satisfaction, Corporate Safety, and Individual or Team Effectiveness. In 2017, Cost Control and Customer Reliability measures will replace Net Income as noted below.

2017 TIA Measures and Weightings
15% – Corporate Safety 15% – Customer Satisfaction 15% – Cost Control 15% – Customer Reliability 40% – Individual/Team Effectiveness

Provided below are some questions and answers about the new Cost Control and Customer Reliability measures as well as the other TIA measures.

If you have specific questions about your TIA, please contact your manager or the appropriate Human Resources representative**.**

LG&E KU
PPL companies

Employee Bulletin

Are LG&E and KU's TIA measures and weightings changing in 2017?
Yes. Cost Control and Customer Reliability will replace Net Income. The Net Income measure has been replaced with 15 percent assigned to each of the two new measures. Corporate Safety, Customer Satisfaction and Individual/Team Effectiveness weightings have not changed.

TIA Measure	2016 Weighting	2017 Weighting
Corporate Safety	15%	15%
Customer Satisfaction	15%	15%
Cost Control	0%	15%
Customer Reliability	0%	15%
Net Income	30%	0%
Individual/Team Effectiveness	40%	40%

Why were Cost Control and Customer Reliability measures added?
Our strong focus on providing reliable and cost-effective service to our customers is enhanced through effective cost management and ensuring reliability. Employees have significant control over operating costs and contribute directly and indirectly to customer reliability.

How will cost control be measured?
Cost Control will be measured by O&M, which includes all labor and non-labor operation and maintenance costs. These costs include those that are recovered through the Environmental Cost Recovery (ECR), Demand Side Management (DSM) and Gas Line Tracker (GLT) mechanisms, but excludes those items that are classified as Other Income and Expense. The expenses related to fuel for generation, power purchases and gas supply to serve customers are excluded.

How will customer reliability be measured?
Customer Reliability will be measured by our System Average Interruption Duration Index (SAIDI). SAIDI is an industry recognized metric which has been used by the company for many years to measure reliability. By planning and executing restoration activities efficiently to reduce the duration of an outage, our customers are positively impacted.

PPL companies

Employee Bulletin

Why is Corporate Safety an incentive measure?
LG&E and KU have established and continue to maintain a robust safety culture with employees and business partners. Since 2000, the safety performance of the company's employees and contractors has been progressively positive. Recordable Injury and Illness Rates (RIIR) have decreased consistently, enabling the company to rank highly among the industry's top safety performers. As we work toward our goal of zero incidents, LG&E and KU will continue to track injuries through the RIIR. The Days Away Restricted and Transferred (DART) safety measure tracks days away from work or a job restriction or transfers to another position due to a recordable work injury. RIIR and DART each have a 50 percent weighting in the total Corporate Safety measure. The RIIR and DART calculation formulas are measured in accordance with federal Occupational Safety and Health Administration (OSHA) standards.

How is Customer Satisfaction measured?
The company's market research vendor contacts randomly selected LG&E and KU customers and customers from peer group companies and asks them about satisfaction with their respective utilities. The scores are compiled quarterly, and those results are used to rank the utility companies. Our performance ranking determines achievement of the measure.

What are Individual and Team Effectiveness measures?
Individual and Team Effectiveness measures are established each year to ensure we are collectively working to achieve strategic business goals. Goals vary by individual and by department and support respective department business objectives. Team effectiveness measures may include safety, reliability and budget goals. Aligning team measures with performance and operational indicators demonstrates our focus on providing safe, reliable and cost-effective service to our customers.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN	**)**	
ADJUSTMENT OF ITS ELECTRIC AND	**)**	**CASE NO. 2016-00371**
GAS RATES AND FOR CERTIFICATES OF	**)**	
PUBLIC CONVENIENCE AND NECESSITY	**)**	

REBUTTAL TESTIMONY OF
LONNIE E. BELLAR
SENIOR VICE PRESIDENT, OPERATIONS
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: April 10, 2017

Q. Please state your name, position and business address.

A. My name is Lonnie E. Bellar. I am the Senior Vice President of Operations for Louisville Gas and Electric Company ("LG&E" or "Company") and Kentucky Utilities Company ("KU") (collectively "Companies"), and an employee of LG&E and KU Services Company, which provides services to LG&E and KU. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Have your responsibilities with the Companies changed since you filed your direct testimony in this case?

A. Yes. Effective January 15, 2017, I was promoted from Vice President of Gas Distribution (LG&E) to Senior Vice President of Operations for both Companies. I still report directly to Mr. Thompson, who is now serving as President and Chief Operating Officer of the Companies. With the change in position, I am now responsible for oversight of the operational areas previously led directly by Mr. Thompson. My areas of responsibility now include power generation, energy supply and analysis, safety and technical training, electric transmission, and gas and electric distribution. A current copy of my CV is included with this testimony as Appendix A.

Q. Do you concur with Mr. Thompson's direct testimony filed in this case?

A. Yes. Mr. Thompson's direct testimony provides a thorough and accurate overview of the Companies' operations, including their performance under certain key performance indicators, efforts to promote the safety of the public and the Companies' workforce, and the planning and rationale for capital investments and O&M projects designed to improve the reliability of the Companies' power delivery system for the benefit of customers. Mr. Thompson's testimony also properly describes the reasons for the Companies' proposed investment in Distribution Automation ("DA") technology, for which the Companies seek a Certificate of Public Convenience and Necessity ("CPCN") in these proceedings.

Q. Why are you providing the rebuttal testimony for the operational areas covered in Mr. Thompson's direct testimony?

A. Now that I have direct responsibility over the operational areas previously under Mr. Thompson's direct oversight, I will provide additional support and context for the Companies' request for a rate increase from an operational standpoint and rebut intervenor testimony regarding the Companies' operations. Mr. Thompson will still address the Companies' operations from a broader, strategic perspective.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut certain positions taken in the direct testimony of intervenors in this case. Specifically, I will explain: (1) that Mr. Holloway's criticism of the Companies' operational competence is wholly unfounded and refuted by the Companies' record of success in major operational projects; (2) that the Companies have an obligation to make the investments in their transmission infrastructure outlined in the Transmission System Improvement Plan; (3) that the Companies' proposed expenses and plan for a cycled approach to vegetation management are proper; (4) the context and history of the Companies' relationship with their Independent Transmission Organization (ITO) and Regional Transmission Organization (RTO), including the reasons for the Companies' exit from the latter; (5) that the proposed additions of the Gas Service Line Replacement Program and the

Transmission Pipeline Modernization Program to LG&E's existing Gas Line Tracker (GLT) surcharge mechanism should be approved; (6) that the Companies' projected expenses for scheduled outage maintenance of generation plant through the end of the test year are appropriate and normalization of such expenses will not accurately reflect actual expense; and (7) that the Companies should not be restricted from demolishing retired generation plant where demolition best serves the overall interests of customers.

<u>Operational Competence</u>

Q. One of the AG's witnesses, Mr. Holloway, criticizes the Companies' ability to maintain, improve and operate their transmission infrastructure and suggests that the Companies do not have the operational competence to implement their plans. How do the Companies respond?

A. The Companies strongly disagree with Mr. Holloway's assessment, which lacks foundation in any objective facts. Contrary to Mr. Holloway's assertions, the Companies have repeatedly demonstrated their ability to plan for, implement, and complete complex capital projects in a timely and cost-effective manner. The Companies have also demonstrated their ability to maintain and operate power generation and delivery systems safely, reliably, and at costs to customers that compare favorably to utilities nationwide.

Q. What are some examples of the operational successes that demonstrate the Companies' excellence in completing large operations projects?

A. In 2011, the Companies sought and obtained approval of their Environmental Compliance Plans from the Kentucky Public Service Commission ("Commission").[1] These plans included projects for LG&E to spend $1.4 billion to modernize environmental controls on its generating equipment to achieve increased particulate and mercury controls. The LG&E plan included installation of this equipment on all units at Mill Creek and for Unit 1 at the Trimble County generating station. The KU plan called for $900 million in investments for additional air emission controls at its Brown and Ghent generating stations and to convert a coal ash pond at Brown to dry storage. Without exaggeration, these plans involved some of the most significant and complex construction projects in the Companies' history. On December 15, 2011, the Commission approved the Companies' ECR compliance plans.[2] Today, the Companies have all but completed the construction and, by all objective measures, the project was a resounding success. Throughout the construction period, the Companies' construction activities were subject to focused ongoing oversight and monitoring by the Commission, including quarterly reports and on-site inspections and meetings at the Commission. The Companies recently received a letter from the Commission commending the Companies on the success of the ECR compliance plan project:

> The original estimated capital cost of the projects totaled $2.301 billion. The final estimated total cost of the projects is $2 billion. The projects, which will be completed well under

[1] *In the Matter of Application of Kentucky Utilities for Certificates of Public Convenience and Necessity and Approval of its 2011 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2011-00161; *In the Matter of Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of its 2011 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2011-00162.
[2] Orders entered December 15, 2011, in Case Nos. 2011-00161 and 2011-00162.

> budget, within original schedules, and with an outstanding safety record, must be considered very successful by any standard.[3]

Mr. Thompson's testimony highlights another of the Companies' recent operational success stories – the construction of Cane Run 7 – Kentucky's first natural gas fired combined-cycle generating unit. As Mr. Thompson sets out in his testimony, the construction of Cane Run 7 was completed in June 2015, on time, $35 Million under budget, and with an exemplary safety record. The unit is now performing exceptionally well, with outage rates among the best (lowest) in the Companies' generation fleet. Furthermore, in order to connect Cane Run 7 to the electrical grid, the Companies built a new transmission substation. The construction of that substation required a complex set of projects to revise the configuration of the existing transmission lines to connect the new substation, while continuing to operate the existing coal fired generating station. The Companies completed construction of the new substation on schedule, with minimal disruption to generation and transmission operations.

Additionally, in April 2016, the Companies commenced operation of a newly built solar facility at the E.W. Brown generating station. The Brown solar facility is the first of its kind in the Companies' generation fleet, and contains over 44,000 solar panels spread over 50 acres. Construction of the Brown solar facility was completed on schedule. These and many other successful projects demonstrate that the Companies have a consistent track record not only of operational competence, but operational excellence.

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[3] February 13, 2017 Letter from Daryl E. Newby to Christopher M. Garrett, attached hereto as Rebuttal Exhibit LEB-1.

Q. How are the Companies demonstrating their ability to operate and maintain their power delivery systems reliably and efficiently?

A. Not only do the Companies excel at planning and executing major capital projects, they have also demonstrated a long history of competence and success in the day-to-day operation and maintenance of their generation, transmission and distribution systems. Mr. Thompson's testimony includes a litany of performance metrics evidencing the Companies' proficiency in a number of operational areas, including workplace and public safety, generation reliability, transmission and distribution reliability, and customer satisfaction. For example, the Companies' generation fleet consistently achieves outage rates well below (better than) benchmarked median performance according to FERC data, and performed near the top quartile for outage rates for calendar year 2016. Likewise, the Companies' distribution operations historically beat median industry performance for reliability, despite cash costs per MWh that compare favorably to utilities nationwide.[4]

The Companies have also shown both a willingness and institutional capability to implement innovative efficiency programs aimed at improving customer experience and managing power delivery costs. A dozen or more such programs are described in Mr. Thompson's testimony, none of which were discussed by Mr. Holloway in his unsupported critique of the Companies' operational competence.

Q. Do the Companies' customer satisfaction results reflect positively on the competency of the Companies' operational performance?

[4] EDO Business Plan, Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(c), Item I., page 34 of 246.

A. Yes, the Companies' competency in providing safe and reliable service translates into positive customer satisfaction. In fact, in 2016, LG&E and KU achieved a clean sweep in top rankings for all J.D. Power customer satisfaction rankings for which they were eligible, among both residential and business customers. Specifically, LG&E ranked first in three separate J.D. Power customer satisfaction studies, including separate surveys for both business and residential customers: the 2016 Gas Utility Residential Customer Satisfaction Study Midwest Midsize Segment, the 2016 Electric Utility Business Customer Satisfaction Study Midwest Midsize Segment, and the 2016 Gas Utility Business Customer Satisfaction Study Midwest Region. KU ranked first among all included utilities in J.D. Power's 2016 Electric Utility Residential Customer Satisfaction Study Midwest Midsize Segment, demonstrating its high satisfaction marks among residential customers for reliable electric service. KU also ranked second, behind only LG&E, in the J.D. Power 2016 Electric Utility Business Customer Satisfaction Study Midwest Midsize Segment.

Q. In light of your testimony, is there any merit to Mr. Holloway's concern that the Companies lack the competency to implement both AMS and DA on the proposed schedule?

A. None. While Mr. Malloy and Mr. Wolfe offer specific rebuttal to Mr. Holloway's assertions regarding these projects, respectively, the argument that the Companies cannot achieve implementation of both projects due to some perceived (but not substantiated) inability of the Companies to operate their business is just fundamentally untrue. The examples I discuss above, and many others, objectively refute that assertion.

Investment in Transmission Assets

Q. Mr. Holloway (AG) and Mr. Kollen (KIUC) have both argued that the Companies' proposed spending on replacement of transmission assets is unreasonably high based on historical spending. Do you agree?

A. Not at all. The Companies not only *should* incur the proposed expenses as good stewards of the electric transmission system, they have an obligation to do so. Neither Mr. Holloway nor Mr. Kollen has questioned the need to perform the improvements that the Companies have proposed in their Transmission System Improvement Plan ("Transmission Plan"), attached as Exhibit PWT-2 to Mr. Thompson's testimony in this case.[5] To the contrary, Mr. Holloway asserts that "identifying, repairing and replacing defective equipment should be a top priority."[6] The Companies agree, which is the very reason they have embarked on a plan to target and replace aging and vulnerable transmission assets, including defective line equipment, overhead lines, transmission protection and control systems, and breakers, among others.

Historically, the Companies' customers have enjoyed consistently safe and reliable transmission service despite incurring among the lowest transmission-related expenditures compared to all FERC-regulated utilities. Indeed, as the Transmission Plan indicates, the Companies were near the top of the first quartile (lowest cost) for total transmission spending per line mile and total transmission spending per MWh sales from 2011 – 2015. This situation has resulted from the Companies' prudent and

[5] Mr. Kollen suggests that the KU expenses could be deferred. I address that proposal in my testimony in Case No. 2016-00370.
[6] Direct Testimony of Larry W. Holloway, P.E. ("Holloway Testimony"), at 8.

careful management of their transmission system assets. However, due to the age of the transmission infrastructure, additional investment is now required to maintain the level of system reliability that the Companies' customers have come to expect.

Q. Why are the Companies proposing to increase spending on Transmission assets to the levels set forth in Mr. Thompson's testimony?

A. The Transmission Plan thoroughly addresses the need for the Companies to increase their spending now on aging transmission assets. Specifically, the bulk of the Companies' transmission assets were installed between the 1950s and 1980s, meaning a significant portion of those assets are nearing the end of their useful life. Catastrophic failures of transmission equipment, although infrequent, have the potential to cause widespread outages of extended duration. At the same time, the Companies' customers expect increasingly safe and reliable service. Failure to replacing aging transmission system assets now will increase the risk of major service disruptions in the future and will lead to overall decline in transmission system performance.

The Companies' identification of the transmission assets designated for replacement has been intentional and well-reasoned. As outlined in the Transmission Plan, the Companies have conducted a detailed analysis of failures by equipment type, and the potential for such failures to negatively affect system reliability. Those factors, combined with the age of the assets and load served, were considered in identifying the assets to be replaced. Notably, neither Mr. Holloway nor Mr. Kollen has offered testimony criticizing the method by which the Companies identified transmission assets for replacement or the prioritization of those investments.

Q. Mr. Holloway asserts that the increase in transmission spending proposed by the Companies is indicative of past neglect of the system or deferred maintenance. Is that accurate?

A. No. As set forth above, the increased spending is being driven, in part, by the fact that a significant portion of the Companies' transmission assets are approaching the end of their useful life at the same time. Another reason for the increased spending is that more equipment is now being identified as in need of replacement as a result of the Companies' equipment inspection programs. The Companies have always complied with Commission regulations regarding equipment inspections. Historically, those regular inspections were performed primarily from the air. In 2013, the Companies transitioned to a six-year inspection cycle in which all wood structures operating at 69kV or above were subject to detailed ground inspections (climbing poles). This change was, in part, a response to evolving Commission regulations regarding inspection of transmission lines. Those ground inspections have been successful in identifying a higher volume of equipment subject to replacement.

The Companies have not deferred replacement of defective transmission assets identified through these more rigorous inspection programs. As Mr. Holloway's testimony acknowledges, the Companies have incurred year-over-year increases in spending for replacement of transmission assets since 2012. The Companies' combined spending for transmission asset replacements increased from $22.1 Million in 2014 to $61.4 Million in 2016.[7] The Companies immediate response

[7] LG&E Response to AG 1-388; KU Response to AG 1-363.

to the increased volume of identified assets for replacement, including the proposed spending in the forecast test year, demonstrates its commitment to improving and maintaining system assets.

Q. Does Mr. Kollen propose any adjustments to LG&E planned transmission capital spending?

A. No. Mr. Kollen's proposed adjustment is for KU only. He does not propose any adjustment for LG&E.

Q. How do you respond to Mr. Holloway's suggestion that the Commission should question the Companies' ability to execute on its Transmission Plan?

A. Like Mr. Holloway's criticism of the Companies' operational competence generally, this opinion is just that – an opinion based on no objective facts, analysis or demonstrated professional experience in planning, operating or maintaining a transmission system. As I discuss earlier in my testimony, the Companies have consistently demonstrated the ability to plan, implement and complete complex operational projects, and the Transmission Plan is no different. The fact that the Companies have developed the Transmission Plan is itself evidence that they are committed to maintaining and operating their transmission system in a secure, reliable, resilient and cost-effective manner. The year-over-year increases in transmission spending over the past several years also demonstrate the Companies' dedication to supporting and maintaining their transmission assets. Mr. Holloway has offered no support for his subjective skepticism that the Transmission Plan cannot be executed except his own misplaced conception of past care and maintenance of the system.

Q. Should the Commission closely scrutinize the overall level of transmission-related spending as Mr. Holloway suggests?

A. Of course the Commission is free to scrutinize any aspect of the Companies' proposed capital expenditures, including those included in the Transmission Plan. I am confident that the proposals contained in the Transmission Plan will withstand such scrutiny. As described elsewhere in my testimony, the Transmission Plan was developed after thorough analysis and investigation of the Companies' transmission system performance, reliability and safety. It is the product of a concerted effort to assess and propose meaningful, targeted solutions to the problem of aging transmission infrastructure. Mr. Holloway conspicuously fails to offer any criticism of the Companies' analysis or methodology. Nor has Mr. Holloway testified that any specific expenditures are unnecessary or unreasonable in light of the needs identified by the Companies. The proposed spending outlined in the Transmission Plan is thorough, reasonable and does not require adjustment.

Vegetation Management

Q. How did the Companies arrive at the decision to convert from just-in-time tree trimming to a 5-year cycled approach to vegetation management for its lower voltage transmission lines?

A. As Mr. Thompson describes in his testimony, the Companies conducted an analysis of the cause of outage duration on their transmission system, and determined that at least 19% of all transmission SAIDI minutes were caused by tree interference. Based on the experience of the Companies' field technicians, a significant portion of unknown outages are also likely caused by tree interference. In 2014, the Companies commissioned an independent transmission program review conducted by

Environmental Consultants, Inc. ("ECI"), to assess their current vegetation management practices and make recommendations for improvement. The result of that assessment was a report prepared on February 20, 2015, which the Companies have produced in response to discovery in these rate case proceedings.[8]

The ECI report concluded that while the Companies were doing an admirable job of managing transmission line vegetation under current practices, a cycled approach to vegetation management was recommended. A cycled approach will assist the Companies in restoring rights-of way for transmission lines, ultimately resulting in reduced unit production cost and reduced planning efforts through reduced aerial inspections.[9] Furthermore, the Companies expect to achieve added safety and reliability performance once the established rights of way are cleared. The ECI report included a budget for converting to a 5-year cycled approach. The Companies adopted the recommendations of the ECI report and have included proposed expenditures for the 5-year cycled approach in the forecast test year.

Q. Mr. Holloway asserts that the ECI Report did not expressly recommend conversion to a 5-year cyclical approach. Is that correct?

A. No. ECI's first recommendation was for the Companies to "[t]ransition maintenance program to cyclical maintenance."[10] The staffing and budget recommendations necessary to accomplish the switch to cycled maintenance were based on a 5-year cycle.

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[8] ECI Report, KU Response to KIUC 1-30; LG&E Response to KIUC 1-31.
[9] ECI Report, at 12.
[10] ECI Report, at 4.

Q. Do you agree with Mr. Holloway that a cyclical approach to transmission line clearing is the industry norm?

A. Yes, and that is the approach the Companies are taking with lower voltage lines pursuant to the ECI report and the Transmission Plan. I reject Mr. Holloway's assertion that it is "alarming" that the Companies are just now transitioning to cyclical vegetation management. Indeed, the ECI report, which was the culmination of ECI's detailed examination of the Companies' current vegetation management practices, including examination of a large number of the Companies' lines, concluded that the Companies have done an admirable job of managing vegetation using just-in-time trimming.[11]

Q. Mr. Holloway states that a five-year cyclical approach to vegetation management may be too long based on the FERC Vegetation Management Report attached as LWH-3 to his testimony. How do you respond?

A. The FERC report cited by Mr. Holloway identifies a vegetation management study performed by CN Utility Consulting in 2004, suggesting that a five year cycle for vegetation management, while industry-standard, may be inadequate.[12] However, FERC was not so absolute in its own findings, recommending that "the Commission and the states should encourage cost-benefit studies to examine the relative costs and benefits of current and more aggressive vegetation management practices."[13] That is precisely what the Companies did in engaging ECI to conduct a detailed vegetation management review and prepare the resulting study. ECI recommended a five-year

[11] ECI Report, at 12.
[12] Exhibit LWH-3, at 5, 11.
[13] Exhibit LWH-3, at 18.

cyclical approach, and that is the approach the Companies are now adopting for lower voltage lines. A four year cycle would be more expensive for ratepayers and it has not been shown that a shorter cycle is necessary to maintain adequate line clearance for the Companies' transmission lines.

Q. Is there any basis for Mr. Holloway's assertion that he finds it hard to believe the Companies can "ramp up" to support the cycled line clearing approach?

A. None. The Companies have already demonstrated the ability to transition to a cyclical vegetation management approach for higher voltage transmission lines to comply with NERC reliability standards.

Q. Does Mr. Holloway recommend any changes to the Companies' proposed transition to a 5-year cycled approach to vegetation management?

A. No. He purportedly raises it only to "illustrate the significant level of changes the company is considering to address past neglect of its transmission assets."[14] The suggestion of past neglect is expressly refuted by the ECI Report and elsewhere in my testimony.

Q. Mr. Smith and Mr. Kollen both suggest that the cost savings expected after the first full cycle of line clearing is completed in 2022 is speculative. Do you agree?

A. Candidly, it is difficult to project with exact precision the cost savings associated with vegetation management once the lines are cleared due to the existence of numerous variables. Certainly, some cost efficiencies will be achieved. Expenses associated with aerial line inspections, which currently occur three times a year, will be reduced after completion of the first full cycle. Furthermore, the ECI report notes that a

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[14] Holloway Testimony, at 13.

cyclical maintenance schedule will reduce long-term unit production cost (lower vegetation density and shorter height brush) and open up the possibility of additional contracting strategies which may further save clearing expenses. I should note however that long-term cost savings is not the primary driver of the switch to cyclical vegetation management. The primary driver is improved line safety and reliability.

Q. Mr. Kollen testifies that the expected reliability improvement attributable to five-year cyclical maintenance is merely "aspirational," do you agree?

A. No. I acknowledge that the Companies have not quantified a specific SAIDI or SAIFI reduction attributable to the cyclical line clearing program, but that is not the same as saying the expected outage improvement is aspirational. As I indicated previously, the Companies have already initiated cyclical line clearing for higher voltage transmission lines (200 kV and above) to comply with mandatory NERC reliability standards. On those higher voltage lines, there have been no tree related outages and no violations of the relevant standards. The improved vegetation management practices will ensure that the Companies' success with higher voltage lines is replicated for lower voltage lines resulting in fewer tree related outages.

Q. Mr. Kollen asserts that while the Companies are free to change their approach to vegetation management, such a change does not inherently require added expense. Is that correct?

A. No. Mr. Kollen has no relevant professional experience in this area. Conversion to a five-year cyclical approach to vegetation management inherently requires added expense until the first cycle can be completed. ECI stated as much in its report: "In addition, the early years of the conversion to cyclic maintenance may require a higher budget."[15] A primary reason for this is that while clearing activities are required for the lines going on the cycle, the rest of the lines must still be maintained using existing practices. Additionally, line clearing for the cycled lines will involve a significant amount of tree removal which is initially more costly than just-in-time trimming and herbicide application. The Companies' Transmission Plan accounts for these added expenses over the first five-year cycle.

Q. Does KIUC's Response to LG&E's Data Request No. 24, which seeks objective support for Mr. Kollen's testimony on this point, persuade you that his assertion is correct?

A. No. To the contrary, it confirms that Mr. Kollen has no objective basis for his assertion that a change from a targeted to cycled approach to vegetation management does not inherently require additional maintenance expense. Indeed, KIUC asserts that "Mr. Kollen does not believe that any empirical studies are necessary to determine that a change in approach does not inherently require additional maintenance expense." The response makes clear that Mr. Kollen has not considered the change in scope or change in work activities necessitated by a cycled approach to vegetation management, particularly in the initial years as the first cycle is completed.

Q. There is a discrepancy between the recommended budget in the ECI Report and the cost estimates for vegetation management in the Transmission Plan. Mr. Smith points out this discrepancy in his testimony. What accounts for the difference?

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[15] ECI Report, at 12.

A. The ECI Report estimated the "total system cost" for implementation of its vegetation management recommendations to be $56.3 Million."[16] While the Companies' projections for the next five years of vegetation management expense are based on the ECI budget, they are not intended to perfectly align with the ECI projections. It is not an apples to apples comparison. The Companies' projections include only the first 4.5 years of the ECI budgeted amount because it contemplates the start of the cycled clearing program will be in July 2017. The Companies' projections also include numerous line items that are not included in the ECI estimates: expenses associated with the hazard tree removal program, other labor expenses, inspector contract labor, vegetation LiDAR, and environmental mitigation associated with the Indiana bat. An itemization of all expenses included in the Companies' vegetation management projections in the Transmission Plan is attached to my testimony as Rebuttal Exhibit LEB-2. The difference is not the result of a hidden error or mistake as Mr. Smith seems to assert, but a reflection of the care taken by the Companies to prepare their own budget estimates.

Q. What is your response to Mr. Smith's proposed adjustment, which would cut O&M spending for vegetation management to base year levels for the forecast test year?

A. The adjustment should not be made. Mr. Smith's proposed adjustment implies that his opinion is that the cyclical approach to vegetation management should not be implemented. As an initial matter, this is directly contrary to Mr. Holloway's testimony that conversion to a cyclical approach is long overdue. Furthermore, as set

[16] ECI Report, at 3.

forth in the ECI Report, current levels of spending are barely sufficient to cover the just-in-time approach and certainly would not cover the transition to a cyclical approach.[17] Mr. Smith's adjustment appears to be based on nothing more than his misreading of ECI's conclusion that the Companies have done a good job maintaining transmission line vegetation under current practices. However, the Companies' current vegetation management practices and the associated expenses incurred in the base year are not sustainable over the long term. The encroachment of vegetation into rights of way for transmission lines will not stop until the rights of way are cleared. Without line clearing this encroachment will continue, resulting in increased outage frequency and duration due to tree interference with lines, and a corresponding increase in O&M expenditures for line clearing into the future.

Q. If the cycled approach to vegetation management is not adopted, is base year spending on vegetation management an appropriate reference for test year spending as Mr. Smith suggests?

A. Not at all. As set forth above, even if the Companies do not change to a cycled approach to vegetation management on lower voltage transmission lines, costs of maintaining the targeted approach will continue to rise as encroachments into the right of way continue. The Companies have accounted for the costs to transition to the cycled approach in their business plans and the Transmission System Improvement Plan. They have not calculated expense levels if the targeted approach is continued, but such expenses would exceed base year expenses for the reasons

[17] ECI Report, at 12.

described herein. Thus, an adjustment of test year spending on vegetation management to base year levels is not appropriate.

ITO Agreement and RTO Membership

Q. In his testimony, Mr. Holloway suggests that the Commission should review the performance of the Companies' ITO, which he refers to as an Independent Transmission Operator. Please explain what an ITO is and what functions it performs for the Companies.

A. Certainly. The Companies currently have in place a contract with TranServ International, Inc. ("TranServ") to serve as the Companies' Independent Transmission *Organization*, not Operator. The contract was expressly approved by the Commission in May 2012.[18] The Companies' current contract with TranServ is on file with the Commission in Case No. 2012-00031. The Companies have recently renewed their contract with TranServ, with the renewal to take effect on September 1, 2017.[19] The renewal of the TranServ ITO contract was approved by FERC by letter dated March 2, 2017.[20] The Companies are required by FERC to have a relationship with an independent transmission organization to ensure compliance with FERC's Open Access Transmission Tariff (OATT), pursuant to FERC Order 888.

As the Commission noted in the order approving the TranServ contract, the function of an Independent Transmission Organization is to "administer the Companies' OATT and, as such, [the ITO] grants and denies transmission service

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[18] *In the Matter of Application of Kentucky Utilities Company and Louisville Gas & Electric Company to Transfer Control of Certain Transmission Functions*, Case No. 2012-00031, Order of May 11, 2012.
[19] A copy of the FERC submission letter and the renewed contract with TranServ is attached to my testimony as Rebuttal Exhibit LEB-3.
[20] *See* FERC Approval Letter, Mar. 2, 2017, attached hereto as Rebuttal Exhibit LEB-4.

requests pursuant to the OATT, calculates Available Transmission Capacity, performs system impact studies for all interconnections, schedules transmission, administers the Companies' Open-access Same-time Information System, and is responsible for compliance with applicable NERC and South-East Reliability Council requirements in carrying out its ITO functions."[21]

In other words, an ITO does not own or maintain any functional control of the Companies' transmission assets or infrastructure. Rather, its primary function is to ensure that the Companies provide open and non-discriminatory access to the Companies' transmission system to third parties. TranServ has no oversight of the day-to-day operations of the Companies' transmission system and has nothing to do with the care and maintenance of the physical infrastructure of the system.

Q. Does Mr. Holloway's testimony reflect this understanding of the role of the Companies' ITO?

A. No. Mr. Holloway's recommendation that the Companies retain an independent entity to assess the current ITO's performance is based on what he perceives to be deficiencies in the care and maintenance of transmission assets, something that TranServ has no role in performing.

Q. Is a review of the current ITO's performance necessary?

A. No. As set forth above, the Commission approved the Companies' agreement with TranServ in 2012. At that time, the Commission concluded that the Companies' proposal to transfer ITO functions from the previous ITO, SPP, to TranServ should be

[21] May 11, 2012 Order at 2-3.

approved.[22] In so finding, the Commission noted that "such a transfer is for a proper purpose and is consistent with the public interest because TranServ and MAPPCOR [its subcontractor] can perform ITO functions for the Companies in compliance with requirements to provide open access to transmission services at a lower cost to ratepayers and transmission customers."[23] Nothing that has occurred since the 2012 Order materially affects this conclusion. Indeed, as set forth above, FERC has now approved the renewal of the TranServ contract on similar terms.[24] TranServ has properly and cost-effectively performed the narrow functions assigned to it under the Companies' ITO agreement.

Q. Mr. Holloway also testifies that the Companies should revisit membership in an RTO. Please explain what an RTO does.

A. An RTO is a Regional Transmission Organization. RTOs were born out of two major regulatory initiatives by FERC, Order 888 and Order 2000, designed to facilitate regional transmission planning, promote reliability, and ensure open and non-discriminatory access to the transmission system. Membership in RTOs is common in certain parts of the country, but it is not common in the Southeastern United States, where the predominant model for utilities is vertical integration, i.e., utilities that provide generation, transmission and distribution functions.

Q. Do the Companies have experience with membership in an RTO?

A. Yes. In response to the FERC regulations mentioned above, the Companies elected to participate as charter members of the Midcontinent Independent System Operator

[22] May 11, 2012 Order at 11.
[23] May 11, 2012 Order at 11.
[24] A summary of the changes to the TranServ contract is contained in the transmittal letter to FERC attached as Rebuttal Exhibit LEB-3.

(MISO) RTO. MISO received FERC approval to act as an RTO in 2001. However, within a couple years of the Companies' membership in MISO, the structure and function of that organization changed in a way that was not beneficial to the Companies or Kentucky ratepayers. On July 13, 2003, the Commission on its own motion opened an investigation into the Companies' membership in MISO, including an assessment of the costs and benefits of that membership and alternatives to that membership.[25] As part of the Commission investigation proceedings, the Companies requested the Commission to authorize their withdrawal from MISO and instead permit the Companies to contract with an ITO to satisfy its obligations under FERC Orders 888 and 2000.

Q. What were the problems the Companies experienced with membership in MISO?

A. The reasons behind the Companies' request to withdraw from MISO were numerous: (1) with MISO's structural changes, the benefits of remaining in MISO were outweighed by its costs; (2) years after the Companies joined, MISO began operating a Day 2 market, which increased the risk that the Companies would be required to purchase power to serve their native load at a higher cost than they could generate themselves; (3) the Companies were forced to cede significant functional control over their transmission and generation operations and had little say in the governance and direction of regional transmission resource planning; (4) MISO members were required to pay for transmission infrastructure improvements in other states which

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[25] *In the Matter of Investigation into the Membership of Louisville Gas & Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, Case No. 2003-00266.

would have no direct benefit to native load customers; and (5) exit from MISO would not materially impact the reliability of the Companies' service to its customers.[26]

Notably, the AG as intervenor supported the Companies' request in the case, concluding that "[t]he areas of expanded activity [of MISO] and the costs for those activities do not appear to be cost justified for LG&E and KU," and "[a]bsent the ability to clearly determine that a gain in reliability is obtained in return for the added cost of participation in MISO, there appears to be no good reason to continue to participate in MISO."[27]

Ultimately, the Commission agreed with the Companies (and the AG) that membership in MISO was not advantageous for the Companies' customers at the time and approved the withdrawal.[28]

Q. Did RTO membership also present regulatory problems?

A. According to the Commission, yes. Most notably, the Commission found the Companies' participation as a member in MISO's wholesale energy markets stripped the power of the Commission to regulate the costs that were factored into the Companies' retail rates, because those generation costs would be viewed as wholesale transactions subject to a FERC tariff and not Kentucky retail tariffs.[29] The Commission also found that when the Companies' participation in MISO's Day 2 markets resulted in a higher cost generation due to manual redispatches of the Companies' generation resources, the Commission did not have jurisdiction to disallow these additional costs because they are wholesale costs subject to the FERC

[26] *See generally* Order entered May 21, 2006 in Case No. 2003-00266.
[27] Post Hearing Brief of the Attorney General in Case No. 2003-00266, filed April 26, 2004, at 2, 3.
[28] May 21, 2006 Order, at 26-27.
[29] May 21, 2006 Order, at 21.

tariff.[30] The Commission further noted concern that MISO's reach into regional resource adequacy planning and demand-side management (DSM) usurped functions historically within the Commission's jurisdiction.[31]

The regulatory challenges attendant with RTO membership are the subject of a recent case filed by East Kentucky Power Cooperative, in which EKPC alleges that its RTO, PJM Interconnection, has authorized EKPC customers to participate in wholesale energy markets in contravention to Kentucky law and Commission precedent, and that PJM has taken the position that it is not subject to the Commission's jurisdiction in any respect.[32] Similar jurisdictional concerns were a recurrent subject of the Commission proceedings adjudicating the Companies' exit from MISO.

Q. How did the Companies satisfy FERC open access requirements after the exit from MISO?

A. Shortly after the Commission approved the Companies' exit from MISO, it approved the Companies' agreement with Tennessee Valley Authority (TVA) to serve as reliability coordinator and an agreement with Southwest Power Pool, Inc. (SPP) to serve as ITO, which, in combination, performed the transmission reliability and open

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[30] May 21, 2006 Order, at 21.
[31] May 21, 2006 Order, at 22.
[32] *In the Matter of the Application of East Kentucky Power Cooperative, Inc. for a Declaratory Order Confirming the Effect of Kentucky Law and Commission Precedent on Retail Electric Customers· Participation in Wholesale Electric Markets,* Case No. 2017-00129, EKPC Application filed Mar. 10, 2017, at ¶¶ 43-44.

access functions previously served by MISO, without the required participation in wholesale energy markets typical of RTO membership.[33]

Q. What is the Companies' relationship to RTOs now?

A. The Companies are still members of MISO and another RTO, PJM Interconnection, for the purposes of participating in wholesale energy markets. Thus, the Companies can still buy and sell power in those markets, without ceding total functional control over the dispatch of its generation and transmission facilities.

Q. Mr. Holloway is critical of the analysis that the Companies conducted in 2012 to assess the costs and benefits of RTO membership. Is Mr. Holloway correct that assumptions used in that analysis were overly simplistic?

A. No. The assumptions made in the RTO Analysis are reasonable and supported by the Companies experience in MISO and its internal experts. Mr. Holloway offers no support for his speculative assertions.

Q. Please explain.

A. Mr. Holloway argues it is not clear why no FTR/ARR congestion costs or no changes to Locational Marginal Pricing ("LMP") were assumed and speculates that neglecting to consider these costs could greatly impact the costs or benefits of RTO membership. His testimony offers no affirmative evidence in support of this allegation. In discovery, when asked to provide any analyses or studies he has performed or participated in developing regarding utility membership or affiliation with ITOs, TSOs or RTOs, Mr. Holloway cited only to his participation in a committee that

[33] *In the Matter of the Application of Louisville Gas and Electric Company and Kentucky Utilities Company to Transfer Functional Control of their Transmission Facilities*, Case No. 2005-00471, Order entered July 6, 2006. As discussed earlier in my testimony, the contract with SPP to serve as ITO was eventually replaced by the contract with TranServ.

recommended to select Charles River Associates to perform a cost benefit study of the Southwest Power Pool RTO Energy Imbalance Services market more than ten (10) years ago.[34]

Forecasting future LMP, RTO congestion costs, and FTR/ARR revenues is a highly complex analysis that is subject to a broad range of variables. Such studies typically yield a broad range of outcomes. As regulated utilities, the Companies' objective in selecting FTRs/ARRs is to hedge future exposure to congestion costs (i.e., net to zero when considering revenue and cost) and not to speculate based on historical data. For these reasons and the fact that expecting a certain amount of cost or revenue could greatly impact the outcome of the analysis, assuming no costs or revenue from these categories is reasonable.

Mr. Holloway also mentions that the 2012 RTO study did not consider possible income streams from sales into PJM or MISO capacity markets. The Companies are aware that these capacity markets have changed and the rules will continue to change for the foreseeable future, meaning they have not yet matured in the Companies' opinion. The continuing evolution of the capacity markets coupled with the more important fact that RTO load pays for the revenue to generators and is a significant offsetting expense led the Company to assume that the net impact of RTO capacity markets is not significant and no cost or revenue should be assumed.

Q. Would RTO membership assist with cost recovery for jointly dispatched units as Mr. Holloway suggests?

[34] Response of AG to LG&E Data Request No. 4.

A. No. For nearly 20 years, following their merger in 1998, LG&E and KU have jointly operated and planned their generation and transmission systems according to their Power Supply System Agreement (PSSA) and Transmission Coordination Agreement. Both agreements were reviewed by this Commission in connection with the proposed merger and approved by FERC. Cost recovery for jointly owned or jointly dispatched generation units is already allocated among LG&E and KU through the PSSA between the Companies. Fuel cost savings created by the Companies' joint dispatch of their generation fleet are distributed through fuel adjustment clause billings. RTO Membership offers no advantage whatsoever over the PSSA as it pertains to cost recovery for jointly owned or jointly dispatched units or the distribution of fuel cost savings from the joint dispatch of the Companies' generation fleet. Indeed customers could possibly lose the fuel cost savings if functional control over the dispatch of the Companies' generation fleet is transferred to an RTO.

Q. Have the Companies continued to evaluate the costs and benefits of RTO membership since their exit from MISO in 2006?

A. Yes. While the Companies have not conducted a formal analysis of RTO membership since 2012, the Companies continue to evaluate the RTO option and the factors considered in that analysis, including RTO membership costs and governance, infrastructure costs imposed by RTOs on their members, administrative costs, the Companies' operating reserves, trade benefits, and transmission revenues from RTO membership.

Q. Is there any basis for Mr. Holloway's skepticism that the Companies cannot conduct an unbiased RTO analysis and therefore a third-party should do it?

A. Not at all. The Commission has repeatedly reviewed the Companies' planning processes and methods in connection with the Companies' integrated resource plans and found the process, methods and resulting plans to be reasonable. The Companies are in the best position to assess their demand, costs, transmission needs, and risk tolerance into the future, and compare those needs to the advantages and disadvantages associated with RTO membership, and are therefore best situated to perform the ongoing analysis and any more formal analysis in the future. Like his other assertions, Mr. Holloway's testimony provides no evidence supporting his skepticism.

Gas Line Tracker Surcharge Mechanism

Q. AG witnesses Messrs. Smith and Holloway are critical of LG&E's request to add programs to the existing GLT mechanism. Do you agree with that criticism?

A. No. Both Messrs. Smith[35] and Holloway[36] express concerns about LG&E's proposed additions of two programs to the existing GLT mechanism. Mr. Holloway claims that the projects proposed to be added to the GLT mechanism are better suited for base rate recovery and Mr. Smith, in following Mr. Holloway's claim, recommends rate base and other accounting adjustments to reflect rate recovery in base rates rather than through the GLT mechanism. I do not agree that the costs for the proposed additional programs should be recovered in base rates rather than through the GLT mechanism.

Q. Please describe the programs LG&E has proposed to be added to the GLT mechanism.

[35] See Mr. Smith's testimony, pp. 53-55
[36] See Mr. Holloway's testimony, pp. 24-27.

A. I explained those projects in detail in my direct testimony[37] and LG&E has provided additional information about those projects in response to discovery requests.[38] In short, LG&E has proposed the addition of two new programs to be included in the existing GLT mechanism. The first program is the Gas Service Line Replacement Program under which LG&E will replace some 45,000 steel service lines that pose a risk because, if left in service, they will fail from corrosion.[39] Replacement of those lines in a systematic manner over time will eliminate that risk of failure and the systematic cost recovery of that program is perfectly suited to the GLT mechanism. The second program is the Transmission Pipeline Modernization Program which is the next step in LG&E's continuing effort to modernize its infrastructure. Under the initial phase of this program, LG&E will replace approximately 15.5 miles of transmission pipeline within the backbone of its gas transmission system.

Q. Do Messrs. Smith or Holloway question the need for either the Gas Service Line Replacement Program or the Transmission Line Modernization Program?

A. No, not at all. In fact, Mr. Holloway says he "does not dispute that these initiatives will improves safety and are needed"[40] and, as stated, Mr. Smith proposes accounting adjustments by which cost recovery for those projects would be in base rates going forward. Thus, the need for the programs does not appear to be contested. The only issue is how the costs of those programs should be recovered.

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[37] See my direct testimony, pp. 15-24.
[38] See LG&E PSC 2-68, PSC 3-29, AG 1-436, AG 2-53, and AG 2-112.
[39] As I explained in my direct testimony, this program includes addressing active county loops and existing curbed services in the gas system.
[40] See Mr. Holloway's direct testimony, p. 25.

Q. Why is cost recovery of these programs better suited in the GLT mechanism rather than in base rates?

A. According to Mr. Holloway, recovery via the GLT mechanism is not necessary because of the length of the programs and of the Company's practice of filing forward-looking test period rates cases approximately every two years. He argues that because the Gas Service Line Replacement Program is a 15-year program, it covers too long of a period for the GLT mechanism which was originally created for programs that could be completed or substantially completed in five years. In doing so, he seems to be drawing an arbitrary time period beyond which programs are not properly included in a mechanism. But it is not the length of a program that should drive whether its costs are included in base rates or via a mechanism. Rather, it should be driven by the unique needs for each program and the related safety aspects of each program.

Furthermore, if there were any merit to an arbitrary five-year distinction, the fact of the matter is that LG&E has only proposed including what would be Phase 1 of the Transmission Pipeline Modernization Program in the GLT mechanism which covers the period 2017 – 2019. Indeed, while at the same time Mr. Holloway draws his five-year distinction, he recognizes the short duration of that program.[41] As for the Gas Service Line Replacement Program, it is true that it is a 15-year program, but as I explained in my direct testimony, it is heavily weighted during the first three years of the program.[42] Finally, the Commission has approved gas mechanism surcharges for other utilities for gas infrastructure initiative programs with durations

[41] See Mr. Holloway's testimony, p. 25.
[42] See my direct testimony, p. 18.

of much longer than five years. For example, Columbia Gas of Kentucky's main replacement program was initially proposed as a 30-year program[43] and Atmos Energy Corporation's main replacement program was proposed as a 15-year program.[44] It is clear that the length of a program proposed to be included in a surcharge mechanism is not relevant and is created to bolster Mr. Smith's results-oriented claim.

Q. Has the Commission approved programs in the GLT mechanism in the past that are similar to the Gas Service Line Replacement Program and the Transmission Pipeline Modernization Program?

Q. Yes. In Case No. 2012-00222, the Commission initially approved LG&E's GLT mechanism. At that time, the initiatives in the GLT mechanism included replacing customer service risers, replacing and installing service lines, leak mitigation improvement, and main replacements.[45] I provided an update on the progress of those initiatives in my direct testimony. All of those initiatives share a common thread with the Gas Service Line Replacement Program and the Transmission Modernization Program. They are necessary for safety and for the systematic and methodical upgrade of gas infrastructure. The GLT mechanism allows for a dedicated process by which the costs of those systematic safety upgrades can be

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[43] *In the Matter of: Application of Columbia Gas of Kentucky, Inc. for an Adjustment in Rates*, Case No. 2009-00141, Order (Ky. Pub. Serv. Comm'n Oct. 26, 2009)(approving Columbia's Accelerated Main Replacement Program ("AMRP'')); Case No. 2009-00141, Prepared Direct Testimony of David E. Mueller at 23 (Ky. Pub. Serv. Comm'n May 1, 2009)("Columbia estimates it will spend approximately $310 million on its AMRP over 30 years[.]")

[44] *In the Matter of: Application of Atmos Energy Corporation for an Adjustment of Rates*, Case No. 2009-00354, Order (Ky. Pub. Serv. Comm'n May 28, 2010)(approving Atmos' Pipeline Replacement Program ("PRP")); Case No. 2009-00354, Prepared Direct Testimony of Earnest B. Napier, P.E. at 12-13 (Ky. Pub. Serv. Comm'n Oct. 29, 2009)("Through its PRP … Atmos Energy plans to replace these facilities over a period of fifteen (15) years[.]")

[45] I provided an update on those initiatives in my direct testimony, pp. 13-15.

recovered in the same systematic fashion. Existence of the GLT mechanism helps to keep such projects on track from a timing and cost perspective and thereby leads to efficiencies for the benefit of customers. In addition, through the GLT mechanism annual true-up process, the Commission and interested parties have continuous oversight and scrutiny. I would agree that one-time large scale projects, such as the Bullitt County Line project proposed in this case, should be recovered in base rates. But given the advantages and efficiencies achieved by GLT mechanism recovery for the types of projects proposed here, cost recovery via that mechanism is superior. Notably, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") has noted its appreciation of the National Association of Regulatory Commissioners' ("NARUC") efforts in supporting rate mechanisms (like the GLT mechanism) for gas pipeline infrastructure replacement programs and encourages NARUC to provide even further support for such mechanisms.[46]

Q. Is it correct that LG&E could recover the costs of these two programs in base rates?

A. Yes, but despite Mr. Holloway's conclusion that LG&E will be filing another base rate case prior to June 30, 2018 based on projected capital spending and that LG&E is on a two-year cycle of filing rate cases, the truth is that there are countless factors considered in assessing the timing of any rate case. It would be unwise to place projects perfectly suited for the GLT mechanism into base rates thereby hastening the need for another base rate case, all other factors being equal. In other words, all else

[46] See a copy of a letter from PHMSA to NARUC attached as Rebuttal Exhibit LEB-5.

being equal, including these two programs in the GLT mechanism will lead to less frequent rate cases.

Q. Do you have any comments on the discovery requests received from Commission Staff related to the Bullitt County Line project?

A. Yes. Commission Staff asked several discovery requests regarding the Bullitt County Line LG&E plans to construct beginning in 2017. I described the basic aspects of that project in my direct testimony[47] and then provided a wealth of information about the project in response to discovery requests.[48] In particular, Commission Staff asked why LG&E did not seek a certificate of public convenience and necessity (CPCN) for the project (PSC 2-64) and also asked LG&E to provide all the information about the project that would typically be found in an application for a CPCN (PSC 3-26). LG&E explained that a CPCN was not sought because the Bullitt County Line project is an ordinary extension in the usual course of business, but, of course, LG&E provided all the information requested that would be submitted as part of a CPCN application. We continue to believe that the project is an ordinary extension in the usual course of ordinary business and that a CPCN is not necessary. In any event, the Commission has before it all information necessary to review the need for and the reasonableness of the project. No intervenor has expressed a reservation about the project in testimony.

[47] See my direct testimony, pp. 3-4.
[48] See PSC 2-64, PSC 3-24, PSC 3-25, PSC 3-26, AG 1-256, and AG 1-432.

Generation Plant Scheduled Outage Expense

Q. Two intervenors, KIUC and Kroger, have proposed an adjustment to the Companies' forecasted generation plant scheduled outage expense. Please describe the proposals.

A. On behalf of KIUC, Mr. Kollen proposes to "normalize" generation plant scheduled outage expense to an average of the past five years, rather than what is actually forecasted in the test year. Mr. Kollen notes that because major outage maintenance is cyclical, a normalized expense will allow the Companies to recover less than forecasted expenses in the test year, but more than actual costs in years where fewer planned outages are scheduled.

On behalf of Kroger, Mr. Townsend also proposes to normalize the Companies forecasted scheduled outage expense, but based on a four-year historical average, adjusted for retired generation plant (Green River 3 and 4, Haefling 3) and new generation plant (Cane Run 7).

Q. Do either Mr. Kollen or Mr. Townsend question the need to conduct any of the scheduled outage activities planned for the forecast test period?

A. No. They simply question the manner in which the Companies should be permitted to recover those costs in base rates.

Q. Do you agree with the proposals of the intervenors that forecasted scheduled outage expense should be normalized to reflect historic expenses?

A. No. As I set forth in my testimony below, historical scheduled outage expense is not necessarily a good indicator of future outage expense. Major outage maintenance is cyclical, and a five-year historical average will not accurately reflect scheduled outage maintenance activities that must be performed during the forecast test year, nor is it representative of the overall eight-year cycle of scheduled outage maintenance at the Companies' generation stations. Two generation units constructed during the past 8-year cycle, Trimble County 2 and Cane Run 7, are due, respectively, for their first major outage maintenance, and costs associated with maintaining those units are not reflected in historic averages. Furthermore, as new technology, particularly ECR controls, has been added to the Companies' generation plant, scheduled outage maintenance has become increasingly complex, more costly, and requires a longer period of time to complete.

The Companies have gained experience over many years in forecasting scheduled outage maintenance expenses for planning and budgeting purposes. Their forecasts are much more likely to reflect actual expenses going forward than historical averages.

Q. How do the Companies plan and conduct outage-related generation maintenance activities?

A. Generation units are subject to regular outage maintenance schedules. These outages are carefully scheduled to ensure that the Companies can serve their native load and maintain adequate reserve margin at all times. Major turbine/generator maintenance outages on both coal-fired and combustion turbine units are typically scheduled on either a seven or eight year cycle for a particular unit. The duration of these outages varies, but many last around six to eight weeks. Other significant maintenance on the generation plant is performed during major turbine/generator outages. Boiler overhauls on coal-fired units are performed more often, around every two years. In addition to major turbine overhauls, combustion turbine units are subject to combustor inspections roughly every other year, and hot gas path inspections approximately every four years. Other minor planned outage inspections and maintenance activities are scheduled more frequently, with the timing dependent on the requirements of the individual unit.[49]

Q. Why are scheduled outage maintenance expenses projected to be higher in the forecast test year than in recent years?

A. The Companies acknowledge that unit outage maintenance schedules can sometimes cause fluctuations in outage-related expense from year to year. For example, no turbine overhauls were conducted on Mill Creek generating units in either 2015 or 2016, which reduces the historical outage expense associated with these units over a five-year time horizon. But Mill Creek 2 is due for a turbine overhaul in the spring of 2018, during the forecast test period. The outage maintenance must be performed at that time to tie in new environmental equipment designed to reduce coal combustion residuals as required by regulation. Likewise, Trimble County Unit 1 has not been subject to a turbine overhaul since 2009, and Trimble County 2, which went into commercial operation in 2011, is due for its first turbine overhaul during the forecast test period. E.W. Brown Unit 2 is also due for a major turbine overhaul during the forecast test period.

However, planned maintenance schedules are not the only reason that outage expenses are projected to be higher in the forecast test period. Many other factors play a role. Due to the relatively low price of natural gas, the Companies' combustion turbines are being dispatched more frequently to minimize fuel costs to

[49] For a detailed explanation of how inspection and outage intervals are calculated and what they involve, please refer to KU's response to AG 2-100 and Kroger 2-8 and LG&E's response to AG 2-116 and Kroger 2-8.

customers, which results in increased maintenance activities for those units. Furthermore, retirement of older coal-fired units and installation of more efficient generation units, like Cane Run 7, materially impacts scheduled outage maintenance methodologies and planned expenditures, such that historical outage maintenance expenses are simply not comparable to planned expenses.

Planned outage maintenance is now more complex than ever, leading to additional cost. In particular, installation of environmental controls on the Companies' generating units has increased the complexity of outage-related maintenance. Furthermore, the scope of outage maintenance grows and becomes more costly as generation plant ages, in the same way that maintenance on a vehicle becomes more involved as the vehicle ages and parts are in need of replacement. As a result, future outage maintenance on a particular generating unit will naturally involve added complexity and added cost.

Q. In light of your testimony, what is your recommendation to the Commission regarding KIUC's and Kroger's proposed scheduled outage normalization adjustments?

A. The Commission should reject these adjustments. As I describe herein, historical scheduled outage expenditures are not indicative of the Companies' future expenditures, and thus are not reflective of the Companies' actual costs to incur needed outage-related maintenance. Neither Mr. Holloway nor Mr. Townsend has accounted for the nature and scope of outage maintenance activities that must be performed on the Companies' generation fleet during the forecast test year. Neither has considered that changes in generating unit utilization affect needed maintenance going forward. Neither has accounted for increased complexity attendant with outage maintenance of generation assets as they age. Mr. Kollen has not even accounted for the changes in the composition of the Companies' generation fleet (retired units and new units) in proposing his adjustment.

Although unexpected contingencies will undoubtedly occur, the Companies have become sophisticated in projecting scheduled outage expenses based on forecasts. Those forecasts are the best indicators of actual cost and should be included in the Companies' base rates.

Plant Demolition

Q. What major generation plant demolition is scheduled before the end of the forecast test year?

A. As discussed in Mr. Thompson's testimony, the Companies are planning for the demolition of retired coal-fired generation plant at Cane Run, Green River and Paddy's Run. The Cane Run project includes demolition of those coal-fired units for which generation capacity was replaced by Cane Run 7. The Paddy's Run demolition is in progress and is expected be complete by the end of 2017. For a detailed report on the status of these demolition projects, see LG&E's response to KIUC 1-11.

Q. In the context of his discussion regarding net terminal salvage in the Companies' proposed depreciation rates, Mr. Kollen suggests that utilities should be required to retire generation units in place as a matter of course, and demolish them only when there is a legal obligation to do so or it is cost-beneficial to do so. How do you respond?

A. Legal requirements and cost are not the only factors relevant to determining whether to retire generation plant in place or demolish it. The Companies must also consider safety issues associated with decommissioned generating units and the wisdom of leaving such units in place indefinitely. The Companies must consider doing what is in the best interests of their customers, their workforce and the surrounding communities. The Companies must also consider options for the best utilization of property at its generation stations. Demolition of generation plant provides the Companies more flexibility in planning the use of space long into the future. Furthermore, the cost of maintaining and securing decommissioned generation plant is not predictable. As these assets continue to age, maintenance expense could be significantly higher than originally projected. Other unexpected events like vandalism and flooding at decommissioned facilities present potential safety, liability, and expense-related risks.

In the end, the Companies are in the best position to determine whether demolition of generation units or retirement in place best suits the needs of customers. While legal considerations and cost analysis are certainly factors in that determination, they should not be dispositive factors and should not create a presumption that retiring generation facilities in place is the best course of action in every circumstance. If that were the case, retired generation plant may never be demolished.

In the case of the Companies' planned demolitions at Paddy's Run, Cane Run and Green River, the Companies determined that demolition was the proper action from a safety standpoint, and that any excess cost associated with demolition versus retirement in place was offset by the risk of uncertainty of costs associated with maintaining the decommissioned facilities long into the future. Mr. Kollen's testimony offers only speculative assertions and no affirmative evidence to show the planned demolitions can be delayed without compromising safety and potential increases in demolition costs in the future.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Senior Vice President – Operations for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 7th day of April 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

APPENDIX A

Lonnie E. Bellar
Senior Vice President, Operations
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-4830

Education

Bachelors in Electrical Engineering;
University of Kentucky, May 1987
Bachelors in Engineering Arts;
Georgetown College, May 1987
E.ON Academy, Intercultural Effectiveness Program: 2002-2003
E.ON Finance, Harvard Business School: 2003
E.ON Executive Pool: 2003-2007
E.ON Executive Program, Harvard Business School: 2006
E.ON Academy, Personal Awareness and Impact: 2006
Tuck Executive Education Program, Dartmouth University: 2015

Professional Experience

LG&E and KU Services Company

Senior Vice President, Operations	Jan. 2017 – Present
Vice President, Gas Distribution	Feb. 2013 –Jan. 2017
Vice President, State Regulation and Rates	Nov. 2010 – Jan. 2013

E.ON U.S. LLC

Vice President, State Regulation and Rates	Aug. 2007 – Nov. 2010
Director, Transmission	Sept. 2006 – Aug. 2007
Director, Financial Planning and Controlling	April 2005 – Sept. 2006
General Manager, Cane Run, Ohio Falls and Combustion Turbines	Feb. 2003 – April 2005
Director, Generation Services	Feb. 2000 – Feb. 2003
Manager, Generation Systems Planning	Sept. 1998 – Feb. 2000
Group Leader, Generation Planning and Sales Support	May 1998 – Sept. 1998

Kentucky Utilities Company

Manager, Generation Planning	Sept. 1995 – May 1998
Supervisor, Generation Planning	Jan. 1993 – Sept. 1995
Technical Engineer I, II and Senior, Generation System Planning	May 1987 – Jan. 1993

Professional Memberships

Institute of Electrical and Electronics Engineers

Civic Activities

E.ON U.S. Power of One Co-Chair – 2007
Kentucky Science Center – Board of Directors – 2008–Present
Metro United Way Campaign – 2008
UK College of Engineering Advisory Board – 2009 – Present
American Gas Association – Board of Directors – 2013 – Present
Southern Gas Association – Board of Directors – 2013 – Present
Greater Louisville, Inc. – Board of Directors, Executive Committee – 2016–Present

Rebuttal Exhibit LEB-1

Letter from Daryl E. Newby to Christopher M. Garrett

Matthew G. Bevin
Governor

Charles G. Snavely
Secretary
Energy and Environment Cabinet

Commonwealth of Kentucky
Public Service Commission
211 Sower Blvd.
P.O. Box 615
Frankfort, Kentucky 40602-0615
Telephone: (502) 564-3940
Fax: (502) 564-3460
psc.ky.gov

Michael J. Schmitt
Chairman

Robert Cicero
Vice Chairman

Daniel E. Logsdon Jr.
Commissioner

February 13, 2017

Christopher M. Garrett
LG&E and KU Energy LLC
220 West Main Street
P.O. Box 32010
Louisville, KY 40232

Re: Construction Monitoring of the 2011 ECR Compliance Plans for Louisville Gas & Electric and Kentucky Utilities Company

Dear Mr. Garrett,

On January 20, 2017, the Kentucky Public Service Commission received from you the 21st quarterly update and final report summarizing the 2011 ECR Compliance Plans for Louisville Gas & Electric Company (LG&E) and Kentucky Utilities Company (KU) (jointly "the Companies").

The Companies' environmental compliance plans were approved by the Commission in Case Nos. 2011-00161 (KU) and 2011-00162 (LG&E). In approving the environmental compliance plans, the Commission found it appropriate to utilize the assistance of an external consultant, to monitor and report the progress of the construction of the approved projects. The selected consultant, Vantage Consulting, LLC, has submitted its final report regarding the projects.

The original estimated capital cost of the projects totaled $2.301 billion. The final estimated total cost of the projects is $2 billion. The projects, which will be completed well under budget, within original schedules, and with an outstanding safety record, must be considered very successful by any standard. Commission Staff expresses its appreciation for the Companies' efforts in keeping Vantage and Staff informed regarding the progress of the environmental projects, and appreciates the professional manner in which the Companies have assisted this review.

Sincerely,

Daryl E. Newby
Director, Financial Analysis

Rebuttal Exhibit LEB-2

Vegetation Management Projections in the Transmission Plan

Comparison of Projected Vegetation Management Expenses, Combined Companies

Transmission Plan Budget (2017 – 2021) v. ECI Report (5 year projection)

$ Millions

	Budget	ECI
Vegetation Management Crews	46.1	
Aerial Spraying	4.7	
Sub-total	50.9	56.3
Labor	3.1	
Hazard Tree	5.3	
Inspector Contract Labor	2.2	
Indiana Bat Mitigation	2.1	
Vegetation LiDAR	0.4	
Sub-total	13.2	-
Total	64.1	56.3

Rebuttal Exhibit LEB-3

FERC submission letter and the renewed contract with TranServ

Jennifer Keisling
Senior Corporate Attorney
LG&E/KU Energy, LLC

220 West Main Street
Louisville, Kentucky 40202
T (502) 627-4303
jennifer.keisling@lge-ku.com

January 25, 2017

Hon. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Louisville Gas and Electric Company and Kentucky Utilities Company;
Docket No. ER17-____-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act,[1] and Part 35 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") regulations,[2] Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "LG&E/KU"), hereby tender for filing a new Independent Transmission Organization Agreement ("ITO Agreement") between LG&E/KU and TransServ International, Inc. ("TranServ"). As discussed herein, the existing agreement between LG&E/KU and TranServ expires on August 31, 2017. The terms of the ITO Agreement being submitted with this filing are substantially similar to the terms of the currently effective ITO Agreement located at Attachment Q to the LG&E/KU Joint Pro Forma Open Access Transmission Tariff ("OATT"), with a few modifications discussed further herein.

LG&E/KU respectfully request an effective date for the new ITO Agreement of September 1, 2017. LG&E/KU respectfully request waiver of the Commission's 120-day prior notice limit for consideration of the ITO Agreement now, to ensure that the new agreement has been accepted for filing well in advance of that date.

I. BACKGROUND

LG&E/KU are both public utilities and are wholly-owned subsidiaries of LG&E/KU Energy LLC, a public utility holding company and a wholly-owned subsidiary of PPL Corporation ("PPL"). PPL is headquartered in Allentown, Pennsylvania. LG&E is an electric and natural gas utility based in Louisville, Kentucky. LG&E currently serves customers in

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1 16 U.S.C. § 824d (2016).

2 18 C.F.R. Part 35 (2016).

Louisville and 16 surrounding counties. KU is an electric utility, based in Lexington, Ky., serving 77 Kentucky counties and five counties in Virginia.

LG&E/KU withdrew from the Midwest Independent Transmission System Operator, Inc. ("MISO") regional transmission organization ("RTO") in 2006.[3] As a means of addressing certain market power concerns that had previously been addressed by LG&E/KU's participation in the RTO, LG&E/KU proposed to utilize an ITO.[4] The ITO administers the terms of the OATT and processes transmission service and generator interconnection requests, while LG&E/KU, in their role as the Transmission Owner, provide the actual service to customers.

LG&E/KU selected Southwest Power Pool, Inc. ("SPP") as the first ITO for the LG&E/KU system. LG&E/KU withdrew from MISO on September 1, 2006, and began working with SPP as the ITO. On August 30, 2011, LG&E/KU requested Commission approval of a new ITO agreement with TranServ, to be effective when SPP's agreement terminated on August 31, 2012.[5] LG&E/KU proposed that TranServ, together with its subcontractor MAPPCOR, perform the functions that SPP had previously performed as the ITO.[6] By order dated December 15, 2011, the Commission conditionally accepted TranServ as the new ITO, effective September 1, 2012.[7] Subsequently, in 2015, MAPPCOR tendered its Notice of Contract Termination to TranServ, effective August 31, 2015. On September 1, 2015, TranServ assumed all duties that were initially subcontracted to MAPPCOR under the terms of the ITO Agreement.[8]

TranServ's current ITO contract expires on August 31, 2017. LG&E/KU and TranServ have negotiated and executed a new ITO Agreement, which lays out the terms and conditions pursuant to which TranServ will perform the ITO functions under the OATT, beginning September 1, 2017.

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[3] *Louisville Gas and Elec. Co., et al.*, 114 FERC ¶ 61,282 (2006).

[4] *Id.* at PP 66, 80.

[5] *Louisville Gas and Elec. Co.,* Docket Nos. ER11-4396-000 and EC98-2-000, Filing of Replacement ITO Proposal (Aug. 30, 2011).

[6] *Id.* at 1.

[7] *Louisville Gas and Elec. Co*., 137 FERC ¶ 61,195 (2011).

[8] *Louisville Gas and Elec. Co*., Docket No. ER15-1901-000, Filing of Revised Attachment Q ITO Agreement (June 11, 2015).

II. DESCRIPTION OF THE PROPOSED ITO AGREEMENT AND MODIFICATIONS FROM THE CURRENTLY EFFECTIVE VERSION

The new ITO Agreement with TranServ continues many of the terms of the existing agreement. For example, TranServ will continue perform its duties in an independent, fair, and nondiscriminatory manner, in accordance with Good Utility Practice, the terms and conditions of the OATT, all applicable laws and regulatory requirements (including reliability standards), and any methodologies, process, or procedures that LG&E/KU may develop to ensure system reliability and legal/regulatory compliance.[9] TranServ will also continue to coordinate with Tennessee Valley Authority in its role as the Reliability Coordinator for LG&E/KU's system.[10] However, TranServ and LG&E/KU have agreed to some modifications to the ITO Agreement in order to clarify their respective rights and obligations moving forward:

- TranServ will cooperate with all reasonable requests by LG&E/KU for information, interviews with TranServ personnel, or other support that may be needed to investigate possible FERC, NERC or other compliance violations or prepare for or respond to compliance-related audits, self-certifications, and other inquiries by Regulatory Authorities (whether internal or external).[11]

- TranServ will be prohibited from hiring current or former Company employees until at least one (1) year subsequent to the Company employee's separation from Company. Likewise, Company is prohibited from hiring current or former TranServ employees until one (1) year subsequent to the TranServ employee's separation from TranServ.

- TranServ shall provide prompt notice of new TranServ Personnel or TranServ Designees to Company to assure new persons undergo FERC Standards of Conduct training within the first thirty (30) days of their employment with TranServ.

- Under the new ITO Agreement Compensation for TranServ will be $2,479,543.56 (subject to increases or decreases if there are changes to the services that TranServ provides, as detailed in Section 5 of Appendix A to the ITO Agreement) for the first year of service.[12] This amount will increase 1.5% for each Contract Year under the contract, rather than a 2.5% annual increase under the currently-effective contract.[13] LG&E/KU will also reimburse

[9] ITO Agreement at Section 1.3.

[10] ITO Agreement at Section 1.2.

[11] *Id.*

[12] ITO Agreement at Section 3.1.

[13] *Id.*

TranServ for certain out-of-pocket costs (such as legal support or travel and lodging related to performance of the ITO services).[14]

- The new ITO agreement has removed the provisions which previously obligated LG&E/KU to pay TranServ a true-up payment if TranServ did not receive a minimum level of revenue for System Impact Studies or Interconnection Feasibility Studies.[15]

- The term of the new ITO Agreement will begin on September 1, 2017.[16] Once effective, the ITO Agreement will continue for an initial term of five years, with additional one-year term extensions.[17] The parties have added a new provision stating that three hundred and sixty days prior to the conclusion of the initial term either party may notify the other, in writing, of a desire to amend terms or pricing of the ITO Agreement for the subsequent terms.[18] If no such amendment is agreed upon by 180 days prior to the beginning of the first subsequent term, the ITO Agreement will terminate on the later of (i) the conclusion of the initial term, as defined above, or (ii) receipt of the required regulatory approvals.[19] The ITO Agreement may be terminated at the end of a term upon 180 days' notice by either party,[20] on the fifth anniversary of the agreement's effective date.[21]

- The parties have added a provision regarding early termination, stating that LG&E/KU may terminate the ITO Agreement if the guaranty that TranServ executed November 29, 2016 in favor of LG&E/KU is terminated, and TranServ does not provide a satisfactory replacement guaranty.[22]

- Appendix A to the ITO Agreement, which details the specific duties for TranServ to carry out as the ITO, remains largely unchanged. The only changes to that appendix are:

    - An addition to Section 3.1.5 regarding transmission planning, that both parties will communicate openly and in a timely manner; each will perform their respective work;

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14 ITO Agreement at Section 3.2.

15 *Compare* ITO Agreement at Section 3.3 *with* 2012 ITO Agreement at Section 3.3.

16 ITO Agreement at Section 4.1.

17 *Id.*

18 *Id.*

19 *Id.*

20 ITO Agreement at Section 4.2.

21 ITO Agreement at Section 4.3.

22 ITO Agreement at Section 4.10.

and both will continually work together to improve mutual and individual processes in a joint effort to assure work is completed pursuant to Company standards and deadlines.

- Clarifications to Section 5, that TranServ's compensation may be modified up or down as the result of modifications to the service functions, and that a change to a service function requiring a reduction in personnel qualifies as a Major Change requiring a Change Order prior to implementation.

III. CONTENTS OF FILING, COMMUNICATIONS, EFFECTIVE DATE, WAIVER

In addition to this Transmittal Letter, LG&E/KU have included the following:

- An executed copy of the new ITO Agreement with TranServ;
- A blackline version of the ITO Agreement, showing the revisions to the 2012 ITO Agreement.

All communications with regard to this filing should be directed to the following persons:

Jennifer Keisling
Senior Counsel
LG&E/KU Energy LLC
220 West Main Street
Louisville, KY 40202
Phone (502) 627-4303
e-mail: *jennifer.keisling@lge-ku.com*

Anne K. Dailey
Troutman Sanders LLP
401 9th St. N.W., Suite 1000
Washington, D.C. 20004
Phone (202) 274-2870
e-mail: *anne.dailey@troutmansanders.com*

LG&E/KU propose an effective date of September 1, 2017 for the new ITO Agreement as contained in Attachment Q. LG&E/KU respectfully request waiver of the 120-day limitation for Section 205 filings to permit submission of the new ITO Agreement now. LG&E/KU believe that the terms of the ITO Agreement are just and reasonable; however, early consideration of the ITO Agreement will provide LG&E/KU and TranServ sufficient time to address any issues in the event the Commission requires any changes.

LG&E/KU respectfully request a waiver of any portion of Section 205 or 18 C.F.R. Part 35 that has not been satisfied by this filing.

LG&E/KU respectfully request that the Commission find that the new ITO Agreement with TranServ is just and reasonable, and accept it for filing for the reasons described herein.

IV. CONCLUSION

WHEREFORE, for the foregoing reasons, LG&E/KU hereby respectfully request (1) that the Commission accept their proposed agreement with TranServ for filing pursuant to FPA Section 205 with an effective date of September 1, 2017, and (2) that the Commission grant waiver as requested herein.

Respectfully submitted,

/s/ Jennifer Keisling

Jennifer Keisling
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Attorneys for Louisville Gas and Electric Company and Kentucky Utilities Company

AGREEMENTS BETWEEN THE TRANSMISSION OWNER AND THE ITO AND THE RELIABILITY COORDINATOR

Independent Transmission Organization Agreement

Between

Louisville Gas and Electric Company/
Kentucky Utilities Company

And

TranServ International, Inc.

FINAL

INDEPENDENT TRANSMISSION ORGANIZATION AGREEMENT

This Independent Transmission Organization ("ITO") Agreement (this "Agreement") is entered into on September 1, 2017, between Louisville Gas and Electric Company and Kentucky Utilities Company, corporations organized pursuant to the laws of the Commonwealth of Kentucky (collectively, "Company"), and TranServ International, Inc., an entity organized pursuant to the laws of Delaware ("TranServ"). Company and TranServ may sometimes be individually referred to herein as a "Party" and collectively as the "Parties."

WHEREAS, Company owns, among other things, an integrated electric transmission system ("Transmission System"), over which open access transmission service is provided to customers in the Company's Balancing Authority Area (as that term is defined by the North American Electric Reliability Corporation ("NERC"));

WHEREAS, the Company has an Open Access Transmission Tariff ("OATT") on file with the Federal Energy Regulatory Commission ("FERC")

WHEREAS, Company's current contract with TranServ is scheduled to expire on August 31, 2017;

WHEREAS, Company desires that, upon expiration of the current contract, TranServ will continue its work under this Agreement, as detailed herein;

WHEREAS, Company remains the owner of its Transmission System and shall be the ultimate provider of transmission services to Eligible Customers (as defined in the OATT), including the sole authority to amend the OATT;

WHEREAS, TranServ: (i) is independent from Company; (ii) possesses the necessary competence and experience to perform the functions provided for hereunder; and (iii) is willing to perform such functions under the terms and conditions agreed upon by the Parties as set forth in this Agreement; and

WHEREAS, as part of Company's goal to maintain independence in the operation of its Transmission System in order to prevent any exercise of transmission market power, Company entered into a Reliability Coordinator Agreement (the "Reliability Coordinator Agreement") with the Tennessee Valley Authority, NERC-certified reliability coordinator (the "Reliability Coordinator"), pursuant to which the Reliability Coordinator provides to Company certain required reliability functions.

NOW THEREFORE, in consideration of the mutual promises contained herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties hereby agree as follows:

Section 1 - Services to be Provided; Standards of Performance

1.1 Services. TranServ shall perform, or cause to be performed, the services described in Appendix A hereto as well as any obligations expressly assigned to the ITO under the OATT ("ITO Services") during the Term in accordance with the terms and conditions of this

Agreement, subject to modification pursuant to Section 1.4 hereto.

1.2 Coordination with Reliability Coordinator. In conjunction with its performance of ITO Services, TranServ shall coordinate and cooperate with the Reliability Coordinator in accordance with the terms of the OATT and all NERC and SERC Reliability Corporation ("SERC") requirements. TranServ shall provide to the Reliability Coordinator, subject to the terms and conditions of this Agreement, including TranServ's obligations with respect to Confidential Information in Section 10, any information that the Reliability Coordinator may reasonably request in order to carry out its functions under the Reliability Coordinator Agreement, which agreement is included in the OATT.

1.3 TranServ Performance; Compliance.

1.3.1 Performance. TranServ, TranServ Personnel and any TranServ Designee (as defined in Section 17.5) shall perform TranServ's obligations (including ITO Services) under this Agreement:

(a) in an independent, fair, and nondiscriminatory manner; and

(b) in accordance with:

(i) any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition ("Good Utility Practice"). Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 2 14(a)(4);

(ii) the terms and conditions of the OATT;

(iii) all applicable laws and the requirements of federal and state regulatory authorities, including the Kentucky Public Service Commission ("KPSC"), Department of Energy ("DOE"), FERC, NERC, SERC, and the North American Electric Standards Board ("NAESB") (collectively, "Regulatory Authorities"); and in fulfilling this requirement in this subsection (iii), TranServ will cooperate with all reasonable requests by Company for information, interviews with TranServ personnel, or other support that may be needed to investigate possible FERC, NERC or other compliance violations or prepare for or respond to compliance-related audits, self-certifications, and other inquiries by Regulatory Authorities (whether internal or external); and

(iv) any methodologies, processes, or procedures relating to ITO Services which Company may develop and which Company determines are necessary or appropriate to ensure safe and reliable system operations and compliance with all applicable laws and the applicable requirements of Regulatory Authorities.

1.4 Changes to ITO Services. The Parties agree that all changes to ITO Services resulting from legal and regulatory developments, as well as Company requests, shall be assessed using a change order process. This process will include a written assessment of impacts to ITO Services consistent with Section 5 of Appendix A. Changes will be implemented only after mutual execution of a change document, which may be titled a Change Order or an Amendment. If the Parties are unable to agree on whether a change constitutes a "Minor Change," or a "Major Change," as those terms are used in Section 5 of Appendix A, such Dispute shall be resolved in accordance with Section 3.6.

Section 2 - Independence and Standards of Conduct

2.1 TranServ Personnel. All ITO Services shall be performed by staff members of TranServ ("TranServ Personnel") or TranServ Designees. No TranServ Personnel or TranServ Designee shall also be employed by Company or any of its Affiliates (as defined in FERC's regulations, 18 C.F.R. § 35.34(b)(3) (2011)). TranServ, TranServ Employees, and TranServ Designees shall (i) be Independent of and (ii) shall not discriminate against Company, any of its Affiliates, or any Tariff Participant. For purposes of this Agreement: (a) "Independent" shall mean that TranServ, TranServ Personnel, and any TranServ Designees are not subject to the control of Company, its Affiliates or any Tariff Participant, and have full decision-making authority to perform all ITO Services in accordance with the provisions of this Agreement. Any TranServ Personnel or TranServ Designee owning securities in Company, its Affiliates or any Tariff Participant shall divest such securities within six (6) months of first being assigned to perform such ITO Services, provided that nothing in this Section 2.1 shall be interpreted or construed to preclude any such TranServ Personnel or TranServ Designee from indirectly owning securities issued by Company, its Affiliates or any Tariff Participant through a mutual fund or similar arrangement (other than a fund or arrangement specifically targeted toward the electric industry or the electric utility industry or any segment thereof) under which the TranServ Personnel or the TranServ Designee does not control the purchase or sale of such securities. Participation by any TranServ Personnel or TranServ Designee in a pension plan of Company, its Affiliates or any Tariff Participant shall not be deemed to be a direct financial interest if the plan is a defined-benefit plan that does not involve the TranServ Personnel's or TranServ Designee's ownership of the securities; and (b) "Tariff Participant" shall mean Company Transmission System customers, interconnection customers, wholesale customers, affected transmission providers, any Market Participant (as defined in FERC's regulations, 18 C.F.R. § 35.34(b)(2) (2011)) and similarly qualified third parties within the Company Balancing Authority Area. For the avoidance of doubt, Company shall have no veto authority over the selection of TranServ Personnel or TranServ Personnel matters, including TranServ's appointment of a TranServ Project Manager (as provided in Section 8.2) except that the Company and TranServ hereby agree that TranServ shall be prohibited from hiring current or former Company employees until at least one (1) year subsequent to the Company employee's separation from Company. Likewise, Company is prohibited from hiring current or former TranServ employees until one (1) year subsequent to the TranServ employee's separation from TranServ.

2.2 Standards of Conduct Treatment. All TranServ Personnel and TranServ Designees performing work under this Contract shall be treated, for purposes of the FERC's Standards of Conduct (18 C.F.R. Part 358), as transmission function employees. All restrictions relating to information sharing and other relationships between marketing function employees and transmission function employees, as those terms are defined in the Standards of Conduct, including the non-discrimination requirements contained therein, shall apply to TranServ Personnel and TranServ Designees performing work under this Contract, or likely to become privy to transmission function information. Said TranServ Personnel and TranServ Designees shall participate in any Standards of Conduct training that the Company may request for compliance purposes. TranServ shall provide prompt notice of new TranServ Personnel or TranServ Designees to Company to assure new persons are trained within the first thirty (30) days of their employment with TranServ.

Section 3 - Compensation; Billing and Payment; Performance Review

3.1 Compensation for Services. Company shall pay to TranServ an annual fee for performance of the ITO Services ("Annual Fee"). The Annual Fee (subject to increases or decreases in accordance with Section 5 of Appendix A) shall be $2,479,543.56 for the first Contract Year and shall escalate by one and five/tenths percent (1.5%) of the prior year's Annual Fee for each Contract Year thereafter.

3.2 Out-of-Pocket Costs. Company shall reimburse TranServ for actual out-of-pocket third party costs and expenses, without markup, for (a) regulatory legal support that is reasonably allocable to TranServ's performance of ITO Services, provided that in no event shall Company reimburse TranServ for legal fees associated with any actual or potential Dispute under this Agreement, (b) travel and lodging that are reasonably allocable to TranServ's performance of ITO Services and (c) setting up regular stakeholder meetings (collectively, (a), (b) and (c) are "Out-of-Pocket Costs"); provided, however, that all Out-of-Pocket Costs subject to reimbursement under this Section 3.2 must be reviewed and approved by Company prior to TranServ incurring such expense.

3.3 Payment.

3.4.1 Monthly Payment. TranServ shall deliver to Company monthly invoices by regular mail, facsimile, electronic mail or such other means as the Parties agree. Such invoices shall set forth (i) one-twelfth (1/12) of the Annual Fee for each month in advance, and (ii) any Out-of-Pocket costs incurred during the previous month, provided however, that travel expenses occurring on the last three (3) days of each month may be carried over to future invoices for ease of administration. Company shall make payment of the amount invoiced by wire transfer in immediately available funds to an account specified by TranServ not later than the thirtieth (30^{th}) day after receipt of the invoice, unless such day is not a business day, in which case on the next business day. All such payments shall be deemed made when said wire transfer is received by TranServ. Overdue payments shall accrue interest calculated at the FERC interest rate as defined in 18 C.F.R. §35.19a(2)(iii)(A) (2011) ("FERC Interest Rate").

3.4 Annual Review.

3.4.1 Annual Review. Commencing at the end of each Contract Year, no later than sixty (60) days after the end of each Contract Year, TranServ shall determine and deliver to Company a calculation of TranServ's actual labor in providing ITO Services for the preceding Contract Year ("Annual Labor"). The Annual Labor calculation shall detail the job title and number of full-time employees assigned to ITO Services, and the number of hours spent in performing ITO Services. The Annual Labor shall also include the hours for any tasks which TranServ outsourced to TranServ Designees.

3.5 Compensation Disputes. Notwithstanding the Dispute resolution provisions in Section

8.3, for any Disputes concerning compensation under this Section 3, Company shall timely file notice of such Dispute with FERC and request that FERC resolve such Dispute. TranServ retains the authority to file notice with FERC of any such Dispute if it so desires. If either Party in good faith disputes any invoice submitted by the other Party pursuant to this Agreement, then the disputing Party (i) shall timely pay the other Party the entire invoiced amount and (ii) shall furnish the other Party with a written explanation specifying the amount of and the basis for the Dispute. Within twenty (20) days after resolution of such Dispute, the Party owing money shall pay the other Party the amount owed, if any, together with interest calculated at the FERC Interest Rate.

Section 4 - Term and Termination

4.1 Term. The initial term of this Agreement shall begin on September 1, 2017 ("Commencement Date"), and shall continue for five (5) years thereafter ("Initial Term"). At the conclusion of the Initial Term, this Agreement shall automatically extend for successive one (1) year terms (each a "Subsequent Term"), unless terminated by either Party in accordance with the terms of this Agreement. Three hundred and sixty (360) days prior to the conclusion of the Initial Term either Party may notify the other, in writing, of a desire to amend terms or pricing of this Agreement for the Subsequent Terms. If such amendment is not agreed upon by both parties 180 days prior to the beginning of the first Subsequent Term, the Amendment shall not automatically extend and will terminate on the later of i) the conclusion of the Initial Term, as defined above, or ii) receipt of the regulatory approvals required under Section 4.5. The Initial Term or any Subsequent Terms are each referred to herein as a "Term." For the purposes of this Agreement, a "Contract Year" shall begin on the Commencement Date or anniversary thereof and conclude twelve (12) months thereafter.

4.2 Termination by Either Party. This Agreement may be terminated by either Party at the end of a Term upon prior one hundred eighty (180) days written notice to the other Party, which termination shall be effective upon the later of (i) one hundred eighty (180) days after the date of such written notice, or (ii) receipt of the regulatory approvals required under Section 4.5.

4.3 Immediate Termination.

4.3.1 Termination for Cause. Subject to Section 4.5, either Party may terminate this Agreement upon prior written notice thereof to the other Party if:

(a) Material Failure or Default. The other Party fails, in any material respect, to comply with, observe or perform, or defaults, in any material respect, in the performance of the terms and conditions of this Agreement, and such failure or default remains uncured for thirty (30) days after written notice thereof, provided that such failure or default is susceptible to cure and the other Party is exercising reasonable diligence to cure such failure or default;

(b) Pattern of Failure. It determines, in its reasonable discretion, that there has been a pattern of failure by the other Party to comply with the standards of performance set forth in Section 1.3.1, whether or not such failure is material;

(c) Gross Negligence, Willful Misconduct or Fraud. The other Party commits gross negligence, willful misconduct or fraud in the performance of its obligations under this Agreement;

(d) Material Misrepresentation. Any representation made by the other Party hereunder shall be false or incorrect in any material respect when made and such misrepresentation is not cured within thirty (30) days of such discovery or written notice thereof, or is incapable of cure;

(e) Bankruptcy. The other Party: (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it; (ii) makes an assignment or any general arrangement for the benefit of creditors; (iii) otherwise becomes bankrupt or insolvent (however evidenced); (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets; or (v) is generally unable to pay its debts as they fall due; or

(f) Dissolution. The other Party dissolves or is dissolved or its legal existence is otherwise terminated.

4.3.2 Immediate Termination Not For Cause. Subject to Section 4.5, Company may terminate this Agreement upon thirty (30) days prior written notice thereof to TranServ if:

(a) Failure to Negotiate Amendment. The Parties are unsuccessful in negotiating an amendment or amendments to this Agreement pursuant to Section 17.9;

(b) Regulatory Changes/Modifications. A Regulatory Authority makes any material changes, modifications, additions, or deletions to this Agreement, unless both Parties agree to such changes, modifications, additions, or deletions;

(c) Failure to Receive Regulatory Approval. Prior to the Commencement Date, FERC rejects this Agreement or Company's selection of TranServ as the ITO;

(d) RTO. Company joins a regional transmission organization ("RTO");or

(e) Extended Force Majeure. A Party is excused because of Force Majeure (as defined in Section 11) for more than thirty (30) days from performing any of its material obligations under this Agreement.

4.4 Termination for Lack of Independence. Subject to Section 4.5, Company may terminate this Agreement upon prior written notice thereof to TranServ if FERC or the KPSC issues a final order that declares that TranServ lacks independence from Company and TranServ cannot obtain independence in a reasonable manner or time period.

4.5 Regulatory Approval. No termination of this Agreement shall be effective until approved by FERC and the KPSC. Notice of termination provided pursuant to Sections 4.3 and 4.4 shall become effective immediately upon approval by FERC and the KPSC.

4.6 Return of Materials. Upon any termination of this Agreement TranServ shall timely and in an orderly manner turn over to Company all materials that were prepared or developed pursuant to this Agreement prior to termination, and return or destroy, at the option of Company, all Data and other information supplied by Company to TranServ or created by TranServ on behalf of Company.

4.7 Survival. All provisions of this Agreement which are by their nature or terms intended to survive the termination of this Agreement, including the obligations set forth in Section 7 and Section 10, shall survive termination of this Agreement.

4.8 Compensation for Early Termination.

4.8.1 If Company terminates this Agreement before the end of a Term pursuant to Section 4.3.2 (a), (b), (d) or (e), then Company shall pay to TranServ the Annual Fee(s) through the longer of the end of the Contract Year or for six (6) months subsequent to the date of termination, which fees shall be accelerated hereunder for this purpose, plus any unpaid Out-of-Pocket Costs that TranServ has incurred through the date of any such termination. In the event that this Section 4.8.1 should trigger an acceleration of Annual Fee(s) that would otherwise span multiple years, such fees paid by Company to TranServ shall not include any escalation of one and five/tenths percent (1.5%) as described in Section 3.1 that had not yet been previously applied to the Annual Fee(s).

4.8.2 If Company terminates this agreement before the end of the Term, and such termination is for cause pursuant to Section 4.3.1, then Company shall only be liable for TranServ's Out-of-Pocket Costs incurred pursuant to contracts which extend beyond any early termination date.

4.9 Post-Termination Services. Commencing on the date that any termination becomes effective ("Termination Date") and continuing for up to one hundred eighty (180) days thereafter, TranServ shall (a) provide ITO Services (and any replacements thereof or substitutions therefor), to the extent Company requests such ITO Services to be performed, and (b) cooperate with Company in the transfer of ITO Services (collectively, the "Post-Termination Services") as such services are authorized under a separate agreement between the Parties. TranServ shall, upon Company's request, provide the Post-Termination Services at a cost to be negotiated and mutually agreed to at that time. The quality and level of performance of ITO Services by TranServ shall not diminish. After the expiration of the Post-Termination Services, TranServ shall answer questions from Company regarding ITO Services on an "as needed" basis at TranServ's then-standard billing rates.

4.10 Termination for Guarantee Termination. A guaranty with Open Access Technology International, Inc., in favor of Company and with TranServ as a counterparty was executed (November 29, 2016) (hereinafter "the Guaranty"). Subject to Section 4.5, Company may terminate this Agreement if the Guaranty is terminated and TranServ does not provide a replacement Guaranty determined, by Company, to be satisfactory.

Section 5 - Data Management and Intellectual Property

5.1 Supply of Data. During the Term, Company shall supply to TranServ, and/or grant

TranServ access to all Data that TranServ requests and that TranServ believes is necessary to perform its duties and obligations under this Agreement, including ITO Services. The Parties shall agree upon the initial format and manner in which such Data shall be provided. For purposes of this Agreement, "Data" means all information, text, drawings, diagrams, models, images or sounds which are embodied in any electronic or tangible medium and which (a) are supplied or in respect of which access is granted to TranServ by Company under this Agreement, which shall be Company's Data, (b) are prepared, stored or transmitted by TranServ solely on behalf of Company, which shall be Company's Data; or (c) are compiled by TranServ by aggregating Data owned by Company and Data owned by third parties, which shall be TranServ's Data.

5.2 Property of Each Party. Each Party acknowledges that the other Party's Data and the other Party's software, base data models and operating procedures for software or base data models ("Processes") are the property of such other Party and agrees that it will do nothing inconsistent with such ownership, including preserving all intellectual property and/or proprietary rights in such other Party's Data and Processes as provided in Section 6.

5.3 Data Integrity. Each Party shall reasonably assist the other Party in establishing measures to preserve the integrity and prevent any corruption or loss of Data, and the Parties shall reasonably assist each other in the recovery of any corrupted or lost Data. Each Party shall reasonably retain and preserve any of the other Party's Essential Data that are supplied to it during the Term. "Essential Data" means any Data that is reasonably required to perform ITO Services under this Agreement and that must be retained and preserved according to any applicable law, regulation, reliability criteria, or Good Utility Practice. Each Party shall exercise commercially reasonable efforts to preserve the integrity of the other Party's Data that are supplied to it during the Term, in order to prevent any corruption or loss of the other Party's Data.

5.4 Confidentiality. Each Party's Data shall be treated as Confidential Information in accordance with the provisions of Section 10.

Section 6 - Intellectual Property.

6.1 Ownership. All inventions, discoveries, processes, methods, designs, drawings, blueprints, information, works of authorship, or the like, whether or not patentable or copyrightable (collectively, "Intellectual Property"), which TranServ first conceives, develops, or begins to develop, either alone or in conjunction with Company or others, with respect to ITO Services under this Agreement, shall be jointly owned by Company and TranServ, and each party shall have the right to use such intellectual property unless specifically otherwise specified on a change document hereunder.

6.2 Royalties and License Fees. Unless the Parties otherwise agree in writing, TranServ shall procure and pay all royalties and license fees which may be payable on account of ITO Services or any part thereof. In case any part of ITO Services is held in any suit to constitute infringement and its use is enjoined, TranServ within a reasonable time shall, at the election of Company and as Company's exclusive remedy hereunder, either (a) secure for Company the perpetual right to continue the use of such part of ITO Services by procuring for Company a royalty-free license or such other permission as will enable TranServ to secure the suspension of any injunction, or (b) replace at TranServ's own expense such part of ITO Services with a non-infringing part or modify it so that it becomes non-infringing (in either case with changes in functionality that are acceptable to Company).

Section 7 - Indemnification and Limitation of Liability

7.1 Company Indemnification. Subject to the limitations specified in Section 7.6, Company shall indemnify, release, defend, reimburse and hold harmless TranServ and its directors, officers, employees, principals, representatives and agents (collectively, the "TranServ Indemnified Parties") from and against any and all third party claims (including claims of bodily injury or death of any person or damage to real and/or tangible personal property), demands, liabilities, losses, causes of action, awards, fines, penalties, litigation, administrative proceedings and investigations, costs and expenses, and attorney fees, (each, an "Indemnifiable Loss") asserted against or incurred by any of the TranServ Indemnified Parties arising out of, resulting from or based upon TranServ performing its obligations pursuant to this Agreement, provided, however, that in no event shall Company be obligated to indemnify, release, defend, reimburse or hold harmless the TranServ Indemnified Parties from and against any Indemnified Loss which is caused by the negligence, the gross negligence or willful misconduct of any TranServ Indemnified Party.

7.2 TranServ Indemnification. Subject to the limitations specified in Section 7.6, TranServ shall indemnify, release, defend, reimburse and hold harmless Company and its directors, officers, employees, principals, representatives and agents (collectively, the "Company Indemnified Parties") from and against any and all Indemnifiable Losses asserted against or incurred by any of the Company Indemnified Parties arising out of, resulting from or based upon TranServ's or a TranServ Designee's negligence, gross negligence, or willful misconduct, provided, however, that in no event shall TranServ be obligated to indemnify, release, defend, reimburse or hold harmless any Company Indemnified Parties from and against any Indemnified Loss which is caused by the negligence, gross negligence or willful misconduct of any Company Indemnified Party.

7.3 Regulatory Indemnification. Subject to the limitations specified in Section 7.6, TranServ shall indemnify, release, defend, reimburse and hold harmless any Company Indemnified Parties from and against all regulatory penalties and sanctions (including penalties or sanctions levied by a Regulatory Authority) arising out of, resulting from or based upon TranServ breach of this Agreement, specifically including Section 1.3.1 hereto, provided, however, that in no event shall TranServ be obligated to indemnify, release, defend, reimburse or hold harmless any Company Indemnified Parties from and against any penalty or sanction which is caused by the gross negligence or willful misconduct of any Company Indemnified Party.

7.4 Cooperation Regarding Claims. If an Indemnified Party (which for purposes of this Section 7.4 shall mean an TranServ Indemnified Party or a Company Indemnified Party) receives notice or has knowledge of any Indemnifiable Loss that may result in a claim for indemnification by such Indemnified Party against an Indemnifying Party (which for purposes of this Section 7.4 shall mean Company or TranServ) pursuant to this Section 7, such Indemnified Party shall as promptly as possible give the Indemnifying Party written notice of such Indemnifiable Loss, including a reasonably detailed description of the facts and circumstances relating to such Indemnifiable Loss, a complete copy of all notices, pleadings and other papers related thereto, and in reasonable detail the basis for its claim for indemnification with respect thereto. Failure to promptly give such written notice or to provide such information and documents shall not relieve the Indemnifying Party from the obligation hereunder to respond to or defend the Indemnified Party against such Indemnifiable Loss unless and only to the extent such failure shall materially diminish the ability of the Indemnifying Party to respond to or to defend the Indemnified Party against such Indemnifiable Loss. Except for indemnification for penalties and sanctions under Section 7.3, the Indemnifying Party, upon its acknowledgment in writing of its obligation to indemnify the Indemnified Party in accordance with this Section 7, shall be entitled to assume the defense or to represent the interest of the Indemnified Party with respect to such Indemnifiable Loss, which shall include the right to select and direct legal counsel and other consultants, appear in proceedings on behalf of such Indemnified Party and to propose, accept or reject offers of settlement, all at its sole cost. If and to the extent that the defense or settlement of any Indemnifiable Loss is reasonably likely to involve injunctive, equitable or prospective relief or materially and adversely affect the Indemnified Party's business or operations other than as a result of money damages or other money payments assumed by the Indemnifying Party, then such defense or settlement will be subject to the reasonable approval of the Indemnified Party. Nothing herein shall prevent an Indemnified Party from retaining its own legal counsel and other consultants and participating in its own defense at its own cost and expense.

7.5 Release and Indemnification Regarding Liens. TranServ hereby releases and/or waives for itself and its successors in interest, and for all TranServ Designees and their successors in interest, any and all claims or right of mechanics or any other type of lien to assert and/or file upon Company's or any other party's property or any part thereof as a result of performing ITO Services. TranServ shall execute and deliver to Company such documents as may be required by applicable laws (*i.e.*, partial and/or final waivers of liens and/or affidavits of indemnification) to make this release effective and shall give all required notices to TranServ Designees with respect to ensuring the effectiveness of the foregoing releases against those parties. TranServ shall secure the removal of any lien that TranServ has agreed to release in this Section 7.5 within five (5) working days of receipt of written notice from Company to remove such lien. If not timely removed, Company may remove the lien and charge all costs and expenses including legal fees (for inside and/or outside legal counsel) to TranServ including, without limitation, the costs of bonding off such lien. Company, in its sole discretion, expressly reserves the right to off-set and/or retain any reasonable amount due to TranServ from payment of any one or more of TranServ's invoices upon Company having actual knowledge of any threatened and/or filed liens and/or encumbrances that may be asserted and/or filed by any TranServ Designee and/or third party with respect to the ITO Services, with final payment being made by Company only upon verification that such threatened and/or filed liens and/or encumbrances have been irrevocably satisfied, settled, resolved and/or released (as applicable), and/or that any known payment disputes concerning the ITO Services involving TranServ and any TranServ Designees have been resolved so that no actions, liens and/or encumbrances of any kind or nature will be filed against Company and/or Company's property.

7.6 Limitation of Liability. Other than as provided in Section 7.3, neither Party shall be liable to the other for any special, punitive, or consequential damages arising out of ITO Services, even if advised of the possibility of such damages. Company agrees that ITO Services are not consumer goods for purposes of international, U.S. Federal or U.S. state warranty laws. Indemnification pursuant to Sections 7.1, 7.2, and 7.3, as well as any direct damages to Company arising out of a material breach of this Agreement shall be limited in the aggregate to the total amount of fees actually paid by Company to TranServ under this Agreement through the date that any penalty or judgment is assessed.

Section 8 - Contract Managers; Dispute Resolution

8.1 Company Contract Manager. Company shall appoint an individual (the "Company Contract Manager") who shall serve as the primary Company representative under this Agreement. The Company Contract Manager shall (a) have overall responsibility for managing and coordinating the performance of Company's obligations under this Agreement, and (b) be authorized to act for and on behalf of Company with respect to all matters relating to this Agreement. Notwithstanding the foregoing, the Company Contract Manager may, upon written notice to TranServ, delegate such of his or her responsibilities to other Company employees, as the Company Contract Manager deems appropriate.

8.2 TranServ Project Manager. TranServ shall appoint, among TranServ Personnel, an individual (the "TranServ Project Manager") who shall serve as the primary TranServ representative under this Agreement. The TranServ Project Manager shall have overall responsibility for managing and coordinating the performance of TranServ obligations under this Agreement. Notwithstanding the foregoing, the TranServ Project Manager may, upon written notice to Company, delegate such of his or her responsibilities to other TranServ Personnel, as the TranServ Project Manager deems appropriate.

8.3 Resolution of Disputes. Any dispute, claim or controversy between the Parties arising out of or relating to this Agreement (each, a "Dispute") shall be resolved in accordance with the procedures set forth in this Section 8.3; provided, however, that this Section 8.3 shall not apply to Disputes arising from or relating to (a) the amount of compensation to be paid by Company pursuant to Section 3.1, which shall be resolved pursuant to Section 3.6, (b) confidentiality or intellectual property rights, in which case either Party shall be free to seek available legal or equitable remedies, or (c) alleged violations of the OATT, in which case either Party shall be free to bring the Dispute to FERC.

8.3.1 Notice of Dispute. Each Party shall provide written notice to the other party of any Dispute, including a description of the nature of the Dispute.

8.3.2 Dispute Resolution by Contract Managers. Any Dispute shall first be referred to the Company Contract Manager and TranServ Project Manager, who shall negotiate in good faith to resolve the Dispute.

8.3.3 Dispute Resolution by Executive Management Representatives. If the Dispute is not resolved within fifteen (15) calendar days of being referred to the Company Contract Manager and the TranServ Project Manager pursuant to Section 8.3.2, then each Party shall have five (5) calendar days to appoint an executive management representative who shall negotiate in good faith to resolve the Dispute.

8.3.4 Binding Arbitration. If the Dispute is not resolved within ten (10) calendar days of being referred to executive management representatives, and the amount in dispute or potential damages exceeds $250,000 USD, the Parties shall proceed in good faith to submit immediately the matter to binding arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("AAA") as they may be amended from time to time (the "Arbitration Rules") subject to the following conditions:

(a) The Parties shall give due consideration to using the Expedited Procedures under the Arbitration Rules in any case in which no disclosed claim or counterclaim exceeds $75,000, exclusive of interest and arbitration fees and costs.

(b) The Parties agree that three arbitrators will be used. Each Party will directly appoint one arbitrator of its choosing from a list of members from the National Roster (as that term is used in the Arbitration Rules) provided by the AAA pursuant to R-12, within ten (10) Days after receipt of such names. The two arbitrators so appointed shall select a third arbitrator from the National Roster to serve as chairperson.

(c) "Baseball" arbitration (in which each Party presents a proposed award or resolution and the actual award must be one of the two submitted), or close variants thereof, shall not be used.

(d) The arbitrators have no authority to appoint or retain expert witnesses for any purpose unless agreed to by the Parties.

(e) All arbitration fees and costs shall be borne equally, regardless of which Party prevails.

(f) Each Party shall bear its own costs of legal representation and witness expenses, unless the arbitrator(s) determines that one Party should bear some or all of the costs of legal representation and witness expenses of the other Party.

(g) The Parties waive any right of appeal or recourse to any court except to compel arbitration, to compel the appointment of arbitrators, to stay judicial proceedings pending arbitration, for an injunction pending determination by the arbitrators, for disqualification of arbitrators, for aid in furtherance of arbitration, to confirm the award, to enforce any judgment confirming the award, or in circumstances of fraud or failure to disclose information or documents required by the arbitrators.

(h) The decision or award of a majority of the arbitrators shall govern. The decision or award of the arbitrators shall be final and binding upon the Parties to the same extent and to the same degree as if the matter had been adjudicated by a court of competent jurisdiction and shall be enforceable under the Federal Arbitration Act and applicable states' laws.

8.3.5 Rights and Remedies. If the Dispute is not resolved within ten (10) calendar days of being referred to executive management representatives, and the amount in dispute or potential damages does not exceed $250,000 USD, each Party is free to pursue any rights or remedies it may have at law or equity.

8.4 Rights Under FPA Unaffected. Except as provided in Section 17.2 relating to the variation or amendment of this Agreement, nothing in this Agreement is intended to limit or abridge any rights that Company may have to file or make application before FERC under Section 205 of the Federal Power Act to revise any rates, terms or conditions of the OATT.

8.5 Statute of Limitations; Continued Performance. The Parties agree to waive the applicable statute of limitations during the period of time that the Parties are seeking to resolve a Dispute pursuant to Section 8.3, and the statute of limitations shall be tolled for such period. The Parties shall continue to perform their obligations under this Agreement during the resolution of a Dispute.

Section 9 - Insurance

9.1 TranServ's Insurance Obligation. During the Term, TranServ shall provide and maintain, and shall require TranServ Designees to provide and maintain, the following insurance (and, except with regard to Workers' Compensation, naming Company as additional insured and waiving rights of subrogation against Company and Company's insurance carrier(s)), and TranServ shall submit evidence of such coverage(s) of TranServ and any TranServ Designees to Company prior to the start of ITO Services. Furthermore, TranServ shall notify Company, prior to the commencement of ITO Services, of any threatened, pending and/or paid off claims to third parties, individually or in the aggregate, which otherwise affects the availability of the limits of such coverage(s) inuring to the benefit of Company as hereinafter specified:

9.1.1 Workers' Compensation and Employer's Liability Policy, which shall include provisions required by applicable law in the jurisdiction of location of workers.

9.1.2 Employer's Liability (Coverage B) with limits of One Million Dollars ($1,000,000) Bodily Injury by Accident, each Accident, $1,000,000 Bodily Injury by Disease, each Employee, and including:

(a) a thirty (30) day cancellation clause; and

(b) broad form all states endorsement.

9.1.3 Commercial General Liability Policy, which shall have minimum limits of One Million Dollars ($1,000,000) each occurrence; One Million Dollars ($1,000,000) Products/Completed Operations Aggregate each occurrence; One Million Dollars ($1,000,000) Personal and Advertising Injury each occurrence, in all cases subject to Two Million Dollars ($2,000,000) in the General Aggregate for all such claims, and including:

(a) a thirty (30) day cancellation clause;

(b) Blanket Written Contractual Liability to the extent covered by the policy against liability assumed by TranServ under this Agreement; and

(c) Broad Form Property Damage.

9.1.4 Commercial Automobile Liability Insurance covering the use of all owned, non-owned, and hired automobiles, with a bodily injury, including death, and property damage combined single minimum limit of One Million Dollars ($1,000,000) each occurrence with respect to TranServ's vehicles assigned to or used in performance of ITO Services under this Agreement.

9.1.5 Umbrella/Excess Liability Insurance with minimum limits of Two Million Dollars ($2,000,000) per occurrence; Two Million Dollars ($2,000,000) aggregate, to apply to employer's liability, commercial general liability, and automobile liability.

9.1.6 To the extent applicable, if engineering or other professional services will be separately provided by TranServ as specified in Appendix A, then Professional Liability Insurance with limits of Three Million Dollars ($3,000,000) per occurrence and Three Million Dollars ($3,000,000) in the aggregate, which insurance shall be either on an occurrence basis or on a claims made basis (with a retroactive date satisfactory to Company).

9.2 Quality of Insurance Coverage. The above policies to be provided by TranServ shall be written by insurance companies which are both licensed to do business in the state where ITO Services will be performed and either satisfactory to Company or having a Best Rating of not less than "A-". These policies shall not be materially changed or canceled except with thirty (30) days written notice to Company from TranServ and the insurance carrier. Evidence of coverage, notification of cancellation or other changes shall be mailed to: Attention: Manager, Supply Chain, LG&E and KU Services Company, P.O. Box 32020, Louisville, Kentucky 40232.

9.3 Implication of Insurance. Company reserves the right to request and receive a summary of coverage of any of the above policies or endorsements; however, Company shall not be obligated to review any of TranServ's certificates of insurance, insurance policies, or endorsements, or to advise TranServ of any deficiencies in such documents. Any receipt of such documents or their review by Company shall not relieve TranServ from or be deemed a waiver of Company's rights to insist on strict fulfillment of TranServ's obligations under this Agreement.

9.4 Other Notices. TranServ shall provide written notice of any accidents or claims in connection with ITO Services or this Agreement to Company's Manager, Risk Management at LG&E and KU Services Company, P.O. Box 32030, Louisville, Kentucky 40232.

Section 10 - Confidentiality

10.1 Definition of Confidential Information. For purposes of this Agreement, "Confidential Information" shall mean, in respect of each Party, all information and documentation of such Party, whether disclosed to or accessed by the other Party in connection with this Agreement and which is identified as Confidential Information, or which otherwise would be treated as confidential by the recipient, including confidential information provided by third-parties; provided, however, that the term "Confidential Information" shall not include information that: (a) is independently developed by the recipient, as demonstrated by the recipient's written records, without violating the disclosing Party's proprietary rights; (b) is or becomes publicly known (other than through unauthorized disclosure); (c) is disclosed by the owner of such information to a third party free of any obligation of confidentiality; (d) is already known by the recipient at the time of disclosure, as demonstrated by the recipient's written records, and the recipient has no obligation of confidentiality other than pursuant to this Agreement or any confidentiality agreements between the Parties entered into before the Commencement Date; or (e) is rightfully received by a Party free of any obligation of confidentiality.

10.2 Protection of Confidential Information. All Confidential Information shall be held in confidence by the recipient to the same extent and in at least the same manner as the recipient protects its own Confidential Information, and such Confidential Information shall be used only for purposes of performing obligations under this Agreement. Except as otherwise provided in Section 10.3, neither Party shall disclose, publish, release, transfer or otherwise make available Confidential Information of, or obtained from, the other Party in any form to, or for the use or benefit of, any person or entity without the owner of such information's prior written consent. Each Party shall be permitted to disclose relevant aspects of the other Party's Confidential Information to its officers, directors, agents, professional advisors, contractors, subcontractors (including TranServ Designees) and employees and to the officers, directors, agents, professional advisors, contractors, subcontractors and employees of its Affiliates (collectively, "Representatives"), to the extent that such disclosure is reasonably necessary for the performance of its duties and obligations or the determination, preservation or exercise of its rights and remedies under this Agreement; provided, however, that the recipient shall take all reasonable measures to ensure that Confidential Information is not disclosed or duplicated in contravention of the provisions of this Agreement by such officers, directors, agents, professional advisors, contractors, subcontractors and employees. Recipient agrees to be liable for the wrongful actions of its Representatives under this Section 10.2. The obligations in this Section 10 shall not restrict any disclosure pursuant to any Regulatory Authority if such release is necessary to comply with valid laws, governmental regulations or final orders of regulatory bodies or courts; provided that, other than in respect of disclosures pursuant to Section 10.3, the recipient shall give prompt written notice to the disclosing Party in reasonable time to exercise whatever legal rights the disclosing Party may have to prevent or limit such disclosure. Further, the recipient shall cooperate with the disclosing Party in preventing or limiting such disclosure.

10.3 Regulatory Requests for Confidential Information. Notwithstanding anything in this Section 10 to the contrary, if a Regulatory Authority or its staff, during the course of an investigation or otherwise, requests Confidential Information from TranServ, TranServ shall provide the requested Confidential Information to the requesting Regulatory Authority or its staff within the time provided for in the request for information. In providing the Confidential Information to a Regulatory Authority or its staff, TranServ shall, consistent with 18 C.F.R. § 388.112 (2011) or any other applicable confidentiality regulation, request that the Confidential Information be treated as confidential and non-public by the Regulatory Authority and its staff and that the information be withheld from public disclosure. TranServ shall notify Company when it is notified by the Regulatory Authority or its staff that a request for public disclosure of, or decision to publicly disclose, Confidential Information has been received, at which time either TranServ or Company may respond before such Confidential Information is made public, pursuant to 18 C.F.R. § 388.112 or the applicable confidentiality regulation.

Section 11 - Force Majeure.

11.1 Force Majeure. Neither Party shall be liable to the other Party for any failure or delay of performance hereunder due to an event which (i) is not reasonably foreseeable or within the reasonable control of the Party claiming Force Majeure (the "Claiming Party") or any Person over which the Claiming Party has control, (ii) was not caused by the acts, omissions, negligence, fault or delays of the Claiming Party or any person over whom the Claiming Party has control, (iii) is not an act, event or condition the risks or consequences of which the Claiming Party has expressly agreed to assume pursuant to this Agreement, and (iv) by the prompt exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided (collectively, (i) - (iv) are "Force Majeure"). Force Majeure shall include: acts of God; acts of the public enemy, war, hostilities, invasion, insurrection, riot, civil disturbance, or order of any competent civil or military government; explosion or fire; strikes or lockouts or other industrial action (excluding those of the Claiming Party unless such action is part of a wider industrial dispute materially affecting other employers); labor or material shortage; malicious acts, vandalism or sabotage; action or restraint by court order of any public or governmental authority (so long as the Claiming Party has not applied for or assisted in the application for, and has opposed where and to the extent reasonable, such government action). Neither Party shall be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to Force Majeure, except for the obligation to pay any amount when due, provided that the Claiming Party:

11.1.1 gives prompt written notice to the other Party of the event or circumstance giving rise to the event of Force Majeure;

11.1.2 affords the other Party reasonable access to information about the event or circumstances giving rise to the event of Force Majeure;

11.1.3 takes commercially reasonable steps to restore its ability to perform its obligations hereunder as soon as reasonably practicable, provided that the Claiming Party shall not be obligated to take any steps that are not otherwise in accordance with Good Utility Practice; and

11.1.4 exercises commercially reasonable efforts to perform its obligations hereunder.

Section 12 - Reporting; Audit.

12.1 Regulatory Reporting.

12.1.1 TranServ shall have the authority to report in writing to FERC in respect of any compensation-related Dispute that arises between TranServ and Company pursuant to Section 3.6.

12.1.2 TranServ shall report in writing to FERC every six (6) months (commencing on the six (6) month anniversary of the Commencement Date and every six (6) months thereafter during the Term) in respect of (a) any concerns expressed by stakeholders and TranServ's response to same and (b) any issues or OATT provisions that hinder TranServ from performing its duties and obligations under this Agreement and the OATT.

12.1.3 In addition to the reports provided for above, TranServ shall make such other reports to Regulatory Authorities as may be required by applicable law and regulations or as may be requested by such Regulatory Authorities.

12.2 Books and Records. TranServ shall maintain full and accurate books and records pertinent to this Agreement, and TranServ shall maintain such books and records for a minimum of five (5) years following the expiration or early termination of this Agreement or longer if necessary to resolve a pending Dispute. Company will have the right, at reasonable times and under reasonable conditions, to inspect and audit, or have an independent third party inspect and audit, TranServ's operations, books, and records (a) to ensure compliance with this Agreement, including TranServ's performance of ITO Services in accordance with Section 1.3.1, (b) to verify any cost claims or other amounts due hereunder, and (c) to validate TranServ's internal controls with respect to the performance of ITO Services. TranServ shall maintain an audit trail, including all original transaction records and timekeeping records, of all financial and non-financial transactions and activities resulting from or arising in connection with this Agreement as may be necessary to enable Company or the independent third party, as applicable, to perform the foregoing activities. Company shall be responsible for any costs and expenses incurred in connection with any such inspection or audit, unless such inspection or audit discovers that Company was charged inappropriate or incorrect costs and expenses, in which case, TranServ shall be responsible for a percentage of the costs and expenses incurred in connection with such inspection or audit equal to the percentage variance by which Company was charged inappropriate or incorrect costs and expenses. TranServ shall provide reasonable assistance necessary to enable Company or an independent third party, as applicable, to perform the foregoing activities and shall not be entitled to charge Company for any such assistance. Amounts incorrectly or inappropriately invoiced by TranServ to Company, whether discovered prior to or subsequent to payment by Company, shall be adjusted or reimbursed to Company by TranServ within twenty (20) days of notification by Company to TranServ of the error in the invoice.

Section 13 - Independent Contractor

13.1 TranServ, in performing ITO Services, shall not act as an agent or employee of Company, but shall be and act as an independent contractor and, except as established in Section 1.3.1, shall be free to perform ITO Services by such methods and in such manner as TranServ may choose, doing everything necessary to perform such ITO Services properly and safely and having supervision over and responsibility for the safety and actions of its employees and the suitability of its equipment. TranServ Personnel and TranServ Designees shall not be deemed to be employees and/or agents of Company. TranServ agrees that if any portion of ITO Services are subcontracted to TranServ Designees, such TranServ Designees shall be bound by and observe the conditions of this Agreement to the same extent as required of TranServ. In such event, Company strongly encourages the use of Minority Business Enterprises, Women Business Enterprises and Disadvantaged Business Enterprises, as defined under federal law and as certified by a certifying agency that Company recognizes as proper.

13.2 Notwithstanding any provision in this Agreement to the contrary, unless approved in writing by Company, TranServ shall not (and shall not permit any TranServ Personnel or TranServ Designee to):

13.2.1 Sell, lease, pledge, mortgage, encumber, convey, or make any license, exchange or other transfer, assignment or disposition of any property or assets of Company;

13.2.2 Enter into, amend, terminate, modify or supplement any contract or agreement (including any labor or collective bargaining agreement) on behalf, or in the name, of Company;

13.2.3 Except upon the approval of Company or pursuant to the direction of Company, take any action that would, to TranServ's knowledge: (a) invalidate any warranty that runs to Company under any contract or agreement; or (b) release any person or entity from its obligations under any contract or agreement with Company;

13.2.4 Make any warranty or representation on behalf of Company;

13.2.5 Except as contemplated under Section 7.4, settle, compromise, assign, pledge, transfer, release or consent to the compromise, assignment, pledge, transfer or release of any claim, suit, debt, demand or judgment against or due by Company, or submit any such claim, dispute or controversy to arbitration or judicial process, or stipulate in respect thereof to a judgment, or consent to the same;

13.2.6 Pledge the credit of Company in any way in respect of any commitments for which it has not received express written authorization from Company; or

13.2.7 Engage in any other transaction on behalf of Company not permitted under this Agreement.

Section 14 - Taxes.

Each Party shall be responsible for the payment of its own taxes, including taxes based on its net income, employment taxes of its employees, taxes on any property it owns or leases, and sales, use, gross receipts, excise, value-added or other transaction taxes. Sales and/or use taxes, that become applicable to services performed within Minnesota, shall be added to TranServ fees and compensation otherwise herein described.

Section 15 - Notices.

15.1 Notices. All notices, requests, consents and other communications required or permitted hereunder shall be in writing, signed by the Party giving such notice or communication, and shall be deemed given: (a) upon receipt, when mailed by U.S. certified mail, postage prepaid, return receipt requested; or (b) upon the next business day, when sent by overnight delivery, postage prepaid using a recognized courier service.

If to Company:

LG&E/KU
VP, Transmission
220 West Main St
PO Box 32010
Louisville, KY 40232

If to TranServ:

TranServ International, Inc.
Contracts Administration
3660 Technology Drive NE
Minneapolis, MN 55418

15.2 Changes. Either Party may, from time to time, change the names, addresses, facsimile numbers or other notice information set out in Section 15.1 by notice to the other Party in accordance with the requirements of Section 15.1.

Section 16 - Personnel and Work Conditions; NERC Requirements.

16.1 Applicable Laws and Safety. TranServ agrees to protect TranServ Personnel and

TranServ Designees and be responsible for their performance of the ITO Services, and to protect Company's facilities, property, employees and third parties from damage or injury. TranServ shall at all times be solely responsible for complying with any and all applicable laws and facility rules relating to health and safety, in connection with ITO Services and for obtaining (but only as approved by Company) all permits and approvals necessary to perform ITO Services. Without limiting the foregoing, TranServ agrees to strictly abide by and observe all standards of the Occupational Safety & Health Administration ("OSHA") which are applicable to ITO Services, as well as Company's Contractor Code of Business Conduct and Company's Contractor/Subcontractor Safety Policy which are both hereby incorporated by reference (Contractor hereby acknowledges receipt of a copy of such Company's Contractor Code of Business Conduct and Company's Contractor/Subcontractor Safety Policy) and any other rules and regulations of the Company, all of which are provided to TranServ in writing and incorporated herein by reference. TranServ also agrees to review in good faith and execute any amendments and/or modifications that may be issued in the future by Company from time to time, with respect to Company's Contractor Code of Business Conduct and/or any of its related policies which are the subject of this Section 16, provided however, that TranServ shall not be obliged by such requirement if the requirements conflicts with an alternate regulatory code of conduct imposed on TranServ. In the event TranServ subcontracts any of ITO Services to a TranServ Designee, TranServ shall notify Company in writing of the identity of TranServ Designee before utilizing TranServ Designee. TranServ shall require any TranServ Designees to complete the safety and health questionnaire and checklists provided by Company and shall provide a copy of such documents to Company upon request. TranServ shall conduct, and require such TranServ Designees to conduct, safety audits and job briefings during performance of ITO Services as applicable. In the event such TranServ Designee has no procedure for conducting safety audits and job briefings, TranServ shall include TranServ Designee in its safety audits and job briefings. All applicable safety audits shall be documented in writing by TranServ and such TranServ Designees. TranServ shall provide documentation of any and all audits identifying safety deficiencies and concerns and corrective action taken as a result of such audits to Company semi-monthly. TranServ further specifically acknowledges, agrees and warrants that TranServ has complied, and shall at all times during the term of this Agreement, comply in all respects with all laws, rules and regulations relating to the employment authorization of TranServ Personnel including, but not limited to, the Immigration Reform and Control Act of 1986, as amended, and the Illegal Immigration Reform and Immigrant Responsibility Act of 1996, as amended, whereby TranServ certifies to Company that TranServ has (a) properly maintained, and shall at all times during the term of this Agreement properly maintain all records required by Immigration and Customs Enforcement, such as the completion and maintenance of the Form I-9 for each TranServ employee; (b) that TranServ maintains and follows an established policy to verify the employment authorization of TranServ Personnel; (c) that TranServ has verified the identity and employment eligibility of all TranServ Personnel in compliance with all applicable laws; and (d) that TranServ is without knowledge of any fact that would render any TranServ Personnel or TranServ Designee ineligible to legally work in the United States. TranServ further acknowledges, agrees and warrants that any TranServ Designee shall be required to agree to these same terms as a condition to being awarded any subcontract for such ITO Services.

16.2 Hazards and Training. TranServ shall furnish adequate numbers of trained, qualified, and experienced TranServ Personnel suitable for performance of ITO Services. Such TranServ Personnel shall be skilled and properly trained to perform ITO Services and recognize all hazards associated with ITO Services. Without limiting the foregoing, TranServ shall participate in any safety orientation or other of Company's familiarization initiatives related to safety and shall strictly comply with any monitoring initiatives as determined by Company.

16.3 Drug and Alcohol. TranServ shall develop and strictly comply with any and all drug and alcohol testing requirements as required by applicable laws. TranServ shall provide Company with a copy of its drug and alcohol testing requirements.

16.4 NERC Reliability Standards. The following additional provisions shall apply to the extent TranServ's performance of ITO Services requires physical or electronic access to areas or assets which are located within physical security perimeters as defined by NERC's Reliability Standards for the Bulk Electric Systems of North America (collectively, the "NERC Standards"), including without limitation any Company data center or control center. In the event of TranServ's non-compliance with the NERC Standards referenced in this Section 16.4, Company shall notify TranServ in writing of the non-compliance and specify appropriate remedial actions.

16.4.1 Information Protection. Without compromising the confidentiality provisions in Section 10, TranServ shall at all times comply with the Company's information protection program(s) as defined by CIP-003, R4. Among the information protected by this program are: (i) all operational procedures; (ii) lists of critical cyber assets; (iii) network topology or similar diagrams; (iv) floor plans of computing centers that contain critical cyber assets; (v) equipment layouts of critical cyber assets; (vi) disaster recovery plans; (vii) incident response plans; and (viii) security configuration information. TranServ shall protect this protected information from disclosure consistent with the program.

16.4.2 Access Revocation. TranServ shall immediately advise appropriate Company's management if any TranServ Personnel or TranServ Designees who have key card access to a Company restricted area or electronic access to a protected system no longer require such access.

16.4.3 Training. If any TranServ Personnel require key card access to a Company restricted area or electronic access to a protected system, TranServ shall ensure that such personnel complete, and retake as requested, all necessary NERC training as requested by Company.

16.4.4 Personnel Risk Assessment. If any TranServ Personnel require key card access to a Company restricted area or electronic access to a protected system, TranServ shall ensure that Company receives necessary waivers and information from TranServ Personnel to complete, and repeat as necessary, such background checks as requested by Company.

16.4.5 Continuing Obligations. TranServ further acknowledges that its compliance with the NERC Standards referenced in this Section 16.4 is a continuing obligation during and after the Term. Upon written notice to TranServ, Company shall have the absolute right to audit and inspect any and all information regarding TranServ's compliance with this Section 16.4, and/or to require confirmation of the destruction of any documentation received from or regarding Company. TranServ is encouraged to contact Company's Compliance Department pursuant to Section 16.5 to ensure TranServ understands and complies with this Section 16.4.

16.5 Compliance Department. The Company has a Compliance Department. Should TranServ have actual knowledge of violations of any of the herein stated policies of conduct in this Section 16, or in standards of performance detailed in Section 1.3.1, or have a reasonable basis to believe that such violations have occurred, whether by TranServ Personnel or a TranServ Designee, TranServ has an affirmative obligation to immediately report, at least on an anonymous basis, any such known violations to the Company's Office of Compliance in care of Director, Compliance and Ethics, LG&E/KU Services, 220 West Main Street, Louisville, Kentucky 40202.

16.6 Equal Employment Opportunity. To the extent applicable, TranServ shall comply with all of the following provisions, which are incorporated herein by reference: (i) Equal Opportunity regulations set forth in 41 C.F.R. § 60-1.4(a) and (c), prohibiting employment discrimination against any employee or applicant because of race, color, religion, sex, or national origin; (ii) Vietnam Era Veterans Readjustment Assistance Act regulations set forth in 41 C.F.R. § 60-250.4 relating to the employment and advancement of disabled veterans and Vietnam era veterans; (iii) Rehabilitation Act regulations set forth in 41 C.F.R. § 60-741.4 relating to the employment and advancement of qualified disabled employees and applicants for employment; (iv) the clause known as "Utilization of Small Business Concerns and Small Business Concerns Owned and Controlled by Socially and Economically Disadvantaged Individuals" set forth in 15 USC § 637(d)(3); and (v) the subcontracting plan requirement set forth in 15 USC § 637(d).

Section 17 - Miscellaneous Provisions.

17.1 Governing Law. This Agreement and the rights and obligations of the Parties hereunder shall be governed by and construed in accordance with the laws of the Commonwealth of Kentucky, without giving effect to its conflicts of law rules.

17.2 Amendment. This Agreement shall not be varied or amended unless such variation or amendment is agreed to by the Parties in writing and accepted by applicable Regulatory Authorities. The Parties explicitly agree that neither Party shall unilaterally petition to FERC pursuant to the provisions of Sections 205 or 206 of the Federal Power Act to amend this Agreement or to request that FERC initiate its own proceeding to amend this Agreement. Nothing in this Section 17.2 shall be construed to limit or affect any other rights that the Parties may have as set forth in Section 8.4, the OATT or otherwise.

17.3 Liability of Affiliates. Any and all liabilities of Company and/or its Affiliates under this Agreement shall be several but not joint.

17.4 Publicity. TranServ shall not issue news releases, publicize or issue advertising pertaining to ITO Services or this Agreement without first obtaining the written approval of Company.

17.5 Assignment. Any assignment of this Agreement or any interest herein or delegation of all or any portion of a Party's obligations, by operation of law or otherwise, by either Party without the other Party's prior written consent shall be void and of no effect; provided, however, that consent will not be required for Company to assign this Agreement to an Affiliate or a successor entity that acquires all or substantially all of the operational business assets of the assigning entity whether by merger, consolidation, reorganization, sale, spin-off or foreclosure; provided, further, that such Affiliate or successor entity (a) agrees to assume all obligations hereunder from and after the date of such assignment and (b) has the legal authority and operational ability to satisfy the obligations under this Agreement. As a condition to the effectiveness of such assignment (i) the assignor shall promptly notify the other Party of such assignment, (ii) the Affiliate or successor entity shall provide a confirmation to the other Party of its assumption of assignor's obligations hereunder, and (iii) assignor shall promptly reimburse the other Party, upon receipt of an invoice, for any one-time incremental costs reasonably incurred as a result of such assignment. For the avoidance of doubt, nothing herein shall preclude Company from transferring any or all of its transmission facilities to another entity or disposing of or acquiring any other transmission assets. Notwithstanding anything to the contrary contained in this Section 17.5, TranServ shall be entitled to contract with one or more persons (each, an "TranServ Designee") to perform only those ITO Services which the OATT expressly provides for being performed by a "designee" of TranServ (as opposed to TranServ or TranServ Personnel), provided that TranServ shall not be relieved of any of its obligations, responsibilities or liabilities under this Agreement as a result of contracting with one or more TranServ Designees in accordance with this Section 17.5 and shall be responsible and liable for any ITO Services performed by TranServ Designees.

17.6 No Third Party Beneficiaries. Except as otherwise expressly provided in this Agreement, this Agreement is made solely for the benefit of the Parties and their successors and permitted assigns and no other person shall have any rights, interest or claims hereunder or otherwise be entitled to any benefits under or on account of this Agreement as third party beneficiary or otherwise.

17.7 Waivers. No waiver of any provision of this Agreement shall be effective unless it is signed by the Party against which it is sought to be enforced. The delay or failure by either Party to exercise or enforce any of its rights or remedies under this Agreement shall not constitute or be deemed a waiver of that Party's right thereafter to enforce those rights or remedies, nor shall any single or partial exercise of any such right or remedy preclude any other or further exercise thereof or the exercise of any other right or remedy.

17.8 Enforcement of Rights. Each Party shall have the right to recover from the other Party all expenses, including fees for and expenses of inside and/or outside counsel, arising out of the other Party's breach of this Agreement or any other action to enforce or defend rights hereunder.

17.9 Severability; Renegotiation. The invalidity or unenforceability of any portion or provision of this Agreement shall in no way affect the validity or enforceability of any other portion or provision herein. If any provision of this Agreement is found to be invalid, illegal or otherwise unenforceable, the same shall not affect the other provisions hereof or the whole of this Agreement and shall not render invalid, illegal or unenforceable this Agreement or any of the remaining provisions of this Agreement. If any provision of this Agreement or the application thereof to any person, entity or circumstance is held by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, or if a modification or condition to this Agreement is imposed by such court or regulatory authority, the Parties shall in good faith negotiate such amendment or amendments to this Agreement as will restore the relative benefits and obligations of the Parties immediately prior to such holding, modification or condition.

17.10 Remedies. No remedy conferred by any of the provisions of this Agreement is intended to be exclusive of any other remedy available at law or equity or otherwise. The election of one or more remedies shall not constitute a waiver of the right to pursue any other available remedies.

17.11 Representations and Warranties. Each Party represents and warrants to the other Party as of the date hereof as follows:

17.11.1 Organization. It is duly organized, validly existing and in good standing under the laws of the State in which it was organized, and has all the requisite power and authority to own and operate its material assets and properties and to carry on its business as now being conducted and as proposed to be conducted under this Agreement.

17.11.2 Authority. It has the requisite power and authority to execute and deliver this Agreement and, subject to the procurement of applicable regulatory approvals, to perform its obligations under this Agreement. The execution and delivery of this Agreement by it and the performance of its obligations under this Agreement have been duly authorized by all necessary corporate action required on its part.

17.11.3 Binding Effect. Assuming the due authorization, execution and delivery of this Agreement by the other Party, this Agreement constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency or other similar applicable laws affecting creditors' rights generally, and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

17.11.4 Regulatory Approval. It has obtained or will obtain by the Commencement Date, any and all approvals of, and acceptances for filing by, and has given or will give any notices to, any applicable federal or state authority, including FERC and the KPSC (as applicable), that are required for it to execute, deliver, and perform its obligations under this Agreement.

17.11.5 No Litigation. There are no actions at law, suits in equity, proceedings, or claims pending or, to its knowledge, threatened against it before or by any federal, state, foreign or local court, tribunal, or governmental agency or authority that might materially delay, prevent, or hinder the performance by such entity of its obligations hereunder.

17.11.6 No Violation or Breach. The execution, delivery and performance by it of its obligations under this Agreement do not and shall not: (a) violate its organizational documents; (b) violate any applicable law, statute, order, rule, regulation or judgment promulgated or entered by any applicable federal or state authority, which violation could reasonably be expected to materially adversely affect the performance of its obligations under this Agreement; or (c) result in a breach of or constitute a default of any material agreement to which it is a party.

17.11.7 No Other Warranties. EXCEPT AS PROVIDED IN THIS AGREEMENT, TRANSERV MAKES NO OTHER WARRANTIES OF ANY KIND, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE.

17.12 Further Assurances. Each Party agrees that it shall execute and deliver such further instruments, provide all information, and take or forbear such further acts and things as may be reasonably required or useful to carry out the purpose of this Agreement and are not inconsistent with the provisions of this Agreement.

17.13 Entire Agreement. This Agreement and the Attachments hereto set forth the entire agreement between the Parties with respect to the subject matter hereof, and supersede all prior agreements, whether oral or written, related to the subject matter of this Agreement. The terms of this Agreement and the Attachments hereto are controlling, and no parole or extrinsic evidence, including to prior drafts and drafts exchanged with any third parties, shall be used to vary, contradict or interpret the express terms and conditions of this Agreement.

17.14 Good Faith Efforts. Each Party agrees that it shall in good faith take all reasonable actions necessary to permit it and the other Party to fulfill their obligations under this Agreement. Where the consent, agreement or approval of any Party must be obtained hereunder, such consent, agreement or approval shall not be unreasonably withheld, delayed or conditioned. Where a Party is required or permitted to act, or omit to act, based on its opinion or judgment, such opinion or judgment shall not be unreasonably exercised, other than where expressly provided for herein. To the extent that the jurisdiction of any federal or state authority applies to any part of this Agreement or the transactions or actions covered by this Agreement, each Party shall cooperate with the other Party to secure any necessary or desirable approval or acceptance of such authorities of such part of this Agreement or such transactions or actions.

17.15 Time of the Essence. With respect to all duties, obligations and rights of the Parties specified by Regulatory Authorities, time shall be of the essence in this Agreement.

17.16 Interpretation. Unless the context of this Agreement otherwise clearly requires:

17.16.1 all defined terms in the singular shall have the same meaning when used in the plural and vice versa;

17.16.2 the terms "hereof," "herein," "hereto" and similar words refer to this entire Agreement and not to any particular Section, Attachment or any other subdivision of this Agreement;

17.16.3 references to "Section" or "Appendix" refer to this Agreement, unless specified otherwise;

17.16.4 references to any law, statute, rule, regulation, notification or statutory provision shall be construed as a reference to the same as it applies to this Agreement and may have been, or may from time to time be, amended, modified or re-enacted;

17.16.5 references to "includes," "including" and similar phrases shall mean "including, without limitation;"

17.16.6 the captions, section numbers and headings in this Agreement are included for convenience of reference only and shall not in any way affect the meaning or interpretation of this Agreement;

17.16.7 "or" may not be mutually exclusive, and can be construed to mean "and" where the context requires there to be a multiple rather than an alternative obligation; and

17.16.8 references to a particular entity include such entity's successors and assigns to the extent not prohibited by this Agreement.

17.17 Joint Effort. Preparation of this Agreement has been a joint effort of the Parties and the resulting document shall not be construed more severely against one of the Parties than against the other and no provision in this Agreement is to be interpreted for or against any Party because that Party or its counsel drafted such provision. Each Party acknowledges that in executing this Agreement it has relied solely on its own judgment, belief and knowledge, and such advice as it may have received from its own counsel, and it has not been influenced by any representation or statement made by the other Party or its counsel not contained in this Agreement.

17.18 Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument, binding upon Company and TranServ, notwithstanding that Company and TranServ may not have executed the same counterpart.

The Parties have caused this Independent Transmission Organization Agreement to be executed by their duly authorized representatives as of the dates shown below.

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY

Name: Stephanie R. Pryor
Title: Manager Supply Chain
Date: 12/9/16

TRANSERV INTERNATIONAL, INC.

Name: Sasan Mokhtari, PhD
Title: President & CEO
Date: 12/1/16

LEGAL
12/07/16

Appendix A

Louisville Gas and Electric Company/

Kentucky Utilities Company

INDEPENDENT TRANSMISSION ORGANIZATION

SERVICE SPECIFICATION

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1. Overview

This Appendix A is intended to be consistent with the terms and conditions of the LG&E/KU Open Access Transmission Tariff (OATT), including Attachment P thereto. If there is any conflict between this Appendix A and the OATT, the OATT shall govern. TranServ shall perform its obligations under this Appendix A in accordance with Section 1.3.1 of this Agreement.

The services delegated to TranServ include the administration of the LG&E/KU Open Access Same-time Information System (OASIS), transmission service request evaluation process, Available Transfer Capability (ATC)/ Available Flowgate Capability (AFC) management, study queue administration, study performance, and stakeholder facilitation. TranServ, as the ITO, will administer the OATT granting of service for both short and long-term transmission requests, administer the large generator interconnection request queue, and perform transmission studies. TranServ will facilitate the LG&E/KU long-term transmission planning function and stakeholder processes.

2. Definitions

Company - Louisville Gas and Electric Company/Kentucky Utilities Company (LG&E/KU)

ITO - Independent Transmission Organization

ITO Services - The applicable functions to be performed as specified in the ITO Agreement

RC - Reliability Coordinator

Service Interruption - A Service Interruption is the loss of Service function, under the direct control of TRANSERV with no mutually agreed to work around provided within the Service

Normal Business Hours - TranServ normal business hours are between the hours of 0700 and 1700 CT, Monday-Friday on days other than the holidays listed below:

1. New Year's Day
2. Memorial Day
3. Independence Day
4. Labor Day
5. Thanksgiving

6. Day after Thanksgiving
7. Day before Christmas
8. Christmas Day

3. Roles and Responsibilities for Providing ITO Services

3.1 TranServ

TranServ International, Inc. (TranServ) will provide services to LG&E/KU as the ITO. The services that TranServ will provide include:

3.1.1 Customer Interface

Responsibility for operating and maintaining OASIS website and keeping it up-to-date with Federal Energy Regulatory Commission (FERC) and North American Energy Standards Board (NAESB) posting requirements, including all Order No. 890 posting requirements (such as study performance metrics, Available Transfer Capability (ATC) calculations, etc.). This includes establishing an interface for customers to submit service requests, and oversight and evaluation of ATC values calculated using software procured from Open Access Technology International, Inc. (OATI) and information from the RC. TranServ's responsibilities and duties in administering OASIS will include the following:

- Performing the duties of a Responsible Party as defined in the Commission's OASIS regulations, 18 C.F.R. § 37.5 and FERC Order No. 676.
- Posting information required to be on the Transmission Provider's OASIS under the Commission's OASIS regulations, 18 C.F.R. § 37.6 and FERC Order No. 676.
- Maintaining and retaining information posted on OASIS in accordance with the Commission's regulations, including 18 C.F.R. Parts 37 and 125.
- Establishing and maintaining queues for processing transmission service requests and generator interconnection (GI) requests.
- Participating in the drafting and posting of Business Practices on the OASIS website, including any FERC or NAESB-required Business Practices. Company shall have final review, ownership, and approval for all Business Practices.
- Participating in periodic reviews of, and providing expertise/comments on, the OATT. Company retains final authority over the OATT's content, including retaining the right and responsibility to file changes to the OATT.
- Participating in stakeholder meetings and/or conference calls as required. These stakeholder meetings will include TranServ, Company, Customers (as appropriate) the RC, and other entities as required, to address concerns regarding Company's system,

administration of the OATT, and related issues.

- Responsibility for coordinating with third-party transmission system owners and operators as necessary to support customer service requests. This includes coordinating the provision of any data from Company to the third-party system.
- Management of ATC/AFC Calculation and Posting.
- Implementation of certain aspects of the Congestion Management Process (CMP) established by the Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection LLC (PJM), and TVA.
- Administration of request evaluations for LG&E/KU tariff service.
- Processing of e-Tags as the transmission provider.
- Reviewing software changes requested from OATI, verifying and testing for proper operations before OATI implements those changes.

3.1.2 Transmission Service and Generator Interconnection Requests and Studies

- Receive and process all applications for Point-to-Point, Network Integration Transmission Service (NITS), and for GIs.
- For short-term Point-to-Point Transmission Service requests (i.e., where the request is within the posted ATC horizon), evaluate and approve a request where the posted ATC is sufficient for the requested transaction. If ATC is insufficient, TranServ shall propose conditional service options to the customer in accordance with the OATT, or otherwise deny the service. If the customer accepts conditional service options, TranServ will be responsible for performing biennial reassessments, as provided under the OATT.
- For long-term Point-to-Point Transmission Service requests, NITS, or GI requests:
  - Determine whether a System Impact Study (SIS) is necessary to accommodate the request.
  - Render all study agreements (SIS, Interconnection Feasibility Studies (IFS), Facilities Study (FS), and Feasibility Analysis Studies (FAS)) to customers within the timeframe provided in the OATT.
  - Perform the SIS or FAS in the timeframe provided in the OATT, including clustered SISs when requested by customers and/or Company.
  - Perform the SIS or FAS using Company's planning criteria.

  - For any study that TranServ performs that requires information from Company (e.g., good faith construction estimates that are included in the SIS), request such information from Company no less than ten (10) business days before the expiration of the applicable study period.
  - Complete study reports and post on OASIS within the timeframe required under the OATT.
  - Notify the Company and individual customers of completed study reports, and alert the Company to initiate service agreements, if applicable.
  - Receive customer deposits.
  - Bill customers for SIS, IFS, FS, and FAS as required by the OATT, including provision of an itemized bill for services if requested by a customer.
  - Reimburse Company for any study costs incurred in contributing to the study and render payment to any third-party vendors for work performed.
- Responsible for receiving and processing requests to designate or un-designate Network Resources, as provided under the OATT.
- If a customer requests a modification to its service, or if a customer assigns its transmission service to a third-party who request modification to the service, process those modification requests in accordance with the terms of the OATT.
- Track all study metrics, including data submittals, input validations, modifications, time and costs associated to perform the study.
- Track the performance of all studies and alert Company if a FERC filing requirement or penalty payment has been triggered due to late studies, as described under the OATT.

3.1.3 ATC Calculation

- Calculate ATC as provided for in Attachment C to the OATT. This includes receiving initial AFC values from the RC, calculating final AFC values using the algorithms included in Attachment C, and converting the AFC to ATC using OATI software.
- Post on OASIS the mathematical algorithms used to calculate firm and non-firm AFC. TranServ shall also post the results of the AFC calculations on OASIS.
- Daily review of transmission service requests (TSRs) and eTag action and statistics.

- Daily review of posted AFC/ATC information and investigation into any anomalies.
- Review, observation, and validation of the Total Transfer Capability (TTC) development process.

3.1.4 Interchange and Scheduling

- As the Transmission Service Provider, responsible for the following activities:
  - Confirm that each electronic schedule (e-Tag) has a confirmed transmission service request.
  - Approve the interchange schedules as the transmission service provider.
  - Curtail electronic schedules if requested by the RC or Balancing Authority (BA).
  - Monitor and validate the Net Scheduled Interchange (NSI), as processed by OATI software, to ensure timely creation of the NSI data file with a syntactical quality check on the data set.

3.1.5 Transmission Planning

- TranServ will participate in Company's transmission planning process as outlined in Attachment K to the OATT, including the following activities:
  - Review and approve Company's long-term (generally one year and beyond) plan for the reliability/adequacy of Company's Transmission System.
  - Review and approve Transmission System models (steady state, dynamics, and short circuit).
  - Develop alternatives to Planning Redispatch service.
  - Notify impacted transmission entities of any planned transmission changes that may influence their facilities.
  - Participate with the SPC and associated SPC working groups, as required.
  - Participate in the overall OATT Attachment K process as observer.
  - The Parties agree that the final annual transmission plan and decision of whether/when to construct and expand the system rests with Company.
  - Both parties will communicate openly and in a timely manner; each will perform their respective work; and both will continually work together to improve mutual and individual processes in a joint effort to assure work is completed pursuant to

Company standards and deadlines.

3.1.6 Compliance

- Establish and adhere to a "culture of compliance" for TranServ Personnel and TranServ Designees consistent with FERC's Policy Statement on Compliance, 125 FERC ¶ 61,058 (2008) as may be supplemented or amended by further FERC orders. TranServ shall take such reasonable steps requested by the Company in furtherance of such a culture of compliance.
- In accordance with *Louisville Gas and Electric Company*, 114 FERC ¶ 61,282 at P 152 (2006), provide FERC with semi-annual reports "detailing concerns expressed by stakeholders and [ITO's] response to those concerns as well as any issues or tariff provisions that hinder [ITO] from performing its required duties" as requested.
- Maintain records and provide reports as required by the Kentucky Public Service Commission (KPSC), OATT, Department of Energy (DOE), FERC, NERC, SERC Reliability Corporation (SERC) or NAESB. Without limiting the foregoing, Company may from time-to-time provide TranServ with specific direction as to records that Company expects to support compliance efforts, and TranServ shall maintain such records as directed.
- Assist Company, as requested by Company, in the preparation of applications, audit materials, filings, reports or responses to any Regulatory Authority. Without limiting the foregoing, this assistance may include from time-to-time preparation for (and participation in, if appropriate) FERC or NERC audits and providing event analysis information for FERC, NERC or SERC. TranServ's support shall be provided in a time frame reasonably requested by Company.
- Monitor FERC, NERC, SERC, and NAESB activities for changes in standards or compliance requirements that may require modification to the ITO Services or other coordination with Company. To the extent possible, TranServ shall notify Company of any proposed or pending modifications prior to their implementation. The Parties shall work together to establish a work plan and timetable for implementation of any such changes. The Parties agree that all changes to ITO Services resulting from legal and regulatory developments as well Company requests, shall be assessed using the change order process detailed in Section 5 of this Appendix A.

3.2 Transmission Planner

TranServ will provide certain services to LG&E/KU, the Transmission Planner (TP). The services include:

3.2.1 Customer Interface

- TranServ will participate in the drafting of Business Practices; including any FERC or NAESB required Business Practices. Company shall have final review, ownership, and approval for all Business Practices.
- TranServ will participate in periodic reviews of, and provide expertise/comments on the OATT. Company retains final authority over the OATT's content, including retaining the right and responsibility to file changes to the OATT.
- Responsible for planning, coordinating and holding regular stakeholder meetings and/or conference calls. These stakeholder meetings will include TranServ, Company, and the RC, and other entities as required, to address concerns regarding Company's system, administration of the OATT, and related issues. This activity includes (as necessary) performing background checks for stakeholders who desire access to Critical Energy Infrastructure Information (CEII), preparing meeting materials, facilitating the meeting, and preparing post-meeting minutes for posting on OASIS.
- Responsible for coordinating with third-party transmission system owners and operators as necessary to support customer service requests. This includes coordinating the provision of any data from Company to the third-party system.

3.3 LG&E/KU

TranServ understands that Company has the following responsibilities in support of the ITO Services under this Appendix A:

3.3.1 Customer Interface

- Contracting for the OATI webSmartOASIS service that meets FERC and NAESB requirements.
- Contracting for the OATI webTrans service used to evaluate and take actions on transmission service requests and e-Tags.
- Continuation of Agreement with the RC to provide necessary data for AFC/ATC calculation

and posting processes.

- Final review, ownership, and approval for all Business Practices.
- Final authority over the OATT's content, including the right and responsibility to file changes to the OATT.
- Cooperate in the coordination with third-party systems as necessary to support customer service requests. This includes coordinating the provision of any data from Company to the third-party system.

3.3.2 Compliance

- From time-to-time provide TranServ with specific direction as to records that Company expects to support compliance efforts, TranServ shall maintain such records as directed in order to provide reports as required by the KPSC, OATT, DOE, FERC, NERC, SERC or NAESB.
- Respond to TranServ notifications of FERC, NERC, SERC, and NAESB activities for changes in standards or compliance requirements that may require modification to the ITO Services or other coordination with Company within requested response timelines. Work together with ITO to establish a work plan and timetable for implementation of any such changes. The Parties agree that all changes to ITO Services resulting from legal and regulatory developments as well Company requests, shall be assessed using the change order process detailed in Section 5 of this Appendix A.

4. Customer Support

TranServ will provide support for Service 24-hours per day and 365-days per year by utilizing a single point of contact support staff. During Normal Business Hours the support staff can be contacted by telephone or by e-mail as outlined in published TranServ's ITO Support Information. After Normal Business Hours support is achieved through telephone only. TranServ will take all reasonable effort to ensure that reported problems or other Customer support related events are responded to within 30-minutes of the event notification when ITO Support Procedures are followed.

4.1 Problem Resolution

Problems or outages are reported to TranServ by following customer support processes. All problems or questions are assigned a severity level by mutual agreement of the parties. Problems which are considered Critical or High in severity should be reported to TranServ at any time. Problems considered Medium or Low severity should be reported by phone during business hours or by e-mail at any time. The severity level classifications are defined as follows:

Critical - Problems or issues that are impacting business immediately or impacting grid reliability and action is required prior to next business day.

High - Problems or issues that affect a key functionality of Service component and there is no work around available but immediate business or grid reliability impact is not present.

Medium - Business processes are impacted, but satisfactory work around is in place to avoid business interruptions.

Low - Customer inquiries or reported problems and issues that create nuisances or inconveniences for the customer. Minimal or no business impact is occurring.

Ticket Resolution		
Action	**TranServ Responsibility**	**Time To Remedy**
Correct a 'Critical' severity Problem or Issue	During normal business hours TranServ will respond to reported Critical severity problems and begin corrective action immediately until either a satisfactory work around is in place or problem is resolved. Outside of normal business hours TranServ will respond to reported Critical severity problems within 30-minutes of notification. Escalation to responsible TranServ senior management will occur in all cases.	TranServ will work continuously until resolution is in place. This may include a temporary work around until a permanent correction can be implemented. **Performance goal is to resolve all Critical severity tickets within 4-hours.**
Correct a 'High' severity Problem or Issue	During normal business hours TranServ will respond to reported High severity problems and begin corrective action to resolve with either a satisfactory work around or problem resolution prior to end of business day. Outside of normal business hours TranServ will respond to reported High severity problems within 30-minutes of notification. Escalation to responsible TranServ senior management will occur in all cases.	TranServ will provide an initial problem analysis update within 8-hours at all times. This may include a recommended temporary work around until a permanent correction can be implemented. **Performance goal is to resolve all High severity tickets within 24-hours.**
Correct a 'Medium' severity Problem or Issue	TranServ will schedule corrective action jointly with Customer. Problems of Medium severity should be reported by telephone during business hours or by e-mail at any time.	TranServ will provide an initial problem analysis update within 3-business days of notification of problem. An appropriate action plan and resolution schedule will be mutually agreed to with the Customer. **Performance goal is to resolve all Medium severity tickets by agreed to commitment date.**
Correct a 'Low' severity Problem or Issue	TranServ will schedule corrective action jointly with Customer. Problems of Low severity should be reported by telephone during business hours or by e-mail at any time.	TranServ will provide an initial problem analysis update within 5-business days. An appropriate action plan and resolution schedule will be mutually agreed to with the Customer. **Performance goal is to resolve all Low severity tickets by agreed to commitment date.**

4.1.1 Tickets - OATI webSupport

To ensure all customers of TranServ receive a high level of customer service all calls or e-mails with questions or reported problems are documented in a Ticket. All TranServ staff members utilize OATI webSupport, an issue reporting and assignment platform allowing tracking and confirmed resolution of all issues reported to TranServ. Upon receiving a communication from a customer, TranServ will open a webSupport Ticket. The Ticket contains customer contact information, data metrics on the type of problem, an identification of the TranServ staff member to whom the Ticket is currently assigned, a detailed description of the problem, and a detailed description of the problem's current status which will eventually include a description of how the issue was resolved. The TranServ staff member provides the Ticket number to the customer for all issues not resolved immediately. If the issue cannot be resolved by the TranServ staff member creating the Ticket, the Ticket is reassigned to another member of the TranServ team. The TranServ staff member who initially created the Ticket is expected to use webSupport's monitoring capability to determine unresolved Tickets, and to reassign or escalate it as necessary at any time to promote prompt resolution within response timing guidelines.

4.1.2 Response Time

TranServ support staff will answer all calls as received during normal business hours and take all reasonable effort to resolve issues at the time of call. For issues and problems that are not immediately resolved, TranServ will follow normal processing for assigned severity level and notify customer once resolution occurs.

Calls to support staff outside of normal business hours will be answered as received and customer will be notified within 30-minutes on planned actions to be taken by TranServ support staff in accordance with normal processing for assigned severity level.

4.1.2.1 Ticket Escalation

Problem tickets that cannot be resolved in accordance with normal processing for assigned severity level will be escalated to appropriate TranServ management. Customers may request immediate ticket escalation to appropriate TranServ management.

4.1.2.2 Customer Satisfaction

Customer satisfaction inquiries are automatically sent to customers upon the closing of a ticket. The results of these surveys result in improved performance by customer support staff or changes in business processes.

5. Service Modifications

From time to time Company may require a modification to an existing Service function. Such modifications may be prompted by changes in regulatory compliance requirements, or by a Company request. Minor modifications that require reasonably minimal resource commitment from TranServ staff will be included within a reasonable time period at no cost to Company. Modifications that may have more significant impact on Service design or will impact TranServ staff resource commitments more than minimally will be discussed with Company and may in some instances require additional payment by Company, or likewise, require a decrease in payment by Company. Each of these change requests will be described in a written Change Order. Each Change Order will be scheduled for implementation upon written agreement with Company as to scope, cost and schedule.

5.1 Minor Changes

Any change to an existing Service function that does not have a significant impact on Service design or require TranServ to staff or contract with additional personnel, if even for a brief period of time, to prepare for and/or meet the requirements of the change (a "Minor Change") will be integrated into Company's Service at no cost to Company. A written Change Order will be negotiated and executed between Company and TranServ prior to implementation of any Minor Change.

5.2 Major Changes

Any change to an existing Service function that has a significant impact on Service design or requires TranServ to staff additional or fewer personnel, if even for a brief period of time, in order to prepare for and/or meet the requirements of the change (a "Major Change") will require a written Change Order which must be negotiated and executed between Company and TranServ prior to implementation of any Major Change.

6. Reliability Coordination

TranServ will be required to coordinate its operations with the LG&E/KU designated RC. The RC is responsible for performing certain reliability related tasks for the LG&E/KU system, including acting as the NERC-registered Reliability Coordinator. The RC's responsibilities are detailed in the Reliability Coordinator Agreement and Attachment P to the LG&E/KU OATT.

ATTACHMENT Q

AGREEMENTS BETWEEN THE TRANSMISSION OWNER AND THE ITO AND THE RELIABILITY COORDINATOR

Independent Transmission Organization Agreement

Between

Louisville Gas and Electric Company/
Kentucky Utilities Company

And

TranServ International, Inc.

FINAL

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INDEPENDENT TRANSMISSION ORGANIZATION AGREEMENT

This Independent Transmission Organization ("ITO") Agreement (this "Agreement") is entered into on September 1, 2017, between Louisville Gas and Electric Company and Kentucky Utilities Company, corporations organized pursuant to the laws of the Commonwealth of Kentucky (collectively, "Company"), and TranServ International, Inc., an entity organized pursuant to the laws of Delaware ("TranServ"). Company and TranServ may sometimes be individually referred to herein as a "Party" and collectively as the "Parties."

WHEREAS, Company owns, among other things, an integrated electric transmission system ("Transmission System"), over which open access transmission service is provided to customers in the Company's Balancing Authority Area (as that term is defined by the North American Electric Reliability Corporation ("NERC"));

WHEREAS, the Company has an Open Access Transmission Tariff ("OATT") on file with the Federal Energy Regulatory Commission ("FERC")

WHEREAS, Company's current contract with TranServ is scheduled to expire on August 31, 2017;

WHEREAS, Company desires that, upon expiration of the current contract, TranServ will continue its work under this Agreement, as detailed herein;

WHEREAS, Company remains the owner of its Transmission System and shall be the ultimate provider of transmission services to Eligible Customers (as defined in the OATT), including the sole authority to amend the OATT;

WHEREAS, TranServ: (i) is independent from Company; (ii) possesses the necessary competence and experience to perform the functions provided for hereunder; and (iii) is willing to perform such functions under the terms and conditions agreed upon by the Parties as set forth in this Agreement; and

WHEREAS, as part of Company's goal to maintain independence in the operation of its Transmission System in order to prevent any exercise of transmission market power, Company entered into a Reliability Coordinator Agreement (the "Reliability Coordinator Agreement") with the Tennessee Valley Authority, NERC-certified reliability coordinator (the "Reliability Coordinator"), pursuant to which the Reliability Coordinator provides to Company certain required reliability functions.

NOW THEREFORE, in consideration of the mutual promises contained herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties hereby agree as follows:

Section 1 - Services to be Provided; Standards of Performance

1.1 Services. TranServ shall perform, or cause to be performed, the services described in Appendix A hereto as well as any obligations expressly assigned to the ITO under the OATT ("ITO Services") during the Term in accordance with the terms and conditions of this Agreement, subject to modification pursuant to Section 1.4 hereto.

1.2 Coordination with Reliability Coordinator. In conjunction with its performance of ITO Services, TranServ shall coordinate and cooperate with the Reliability Coordinator in accordance with the terms of the OATT and all NERC and SERC Reliability Corporation ("SERC") requirements. TranServ shall provide to the Reliability Coordinator, subject to the terms and conditions of this Agreement, including TranServ's obligations with respect to Confidential Information in Section 10, any information that the Reliability Coordinator may reasonably request in order to carry out its functions under the Reliability Coordinator Agreement, which agreement is included in the OATT.

1.3 TranServ Performance; Compliance.

1.3.1 Performance. TranServ, TranServ Personnel and any TranServ Designee (as defined in Section 17.5) shall perform TranServ's obligations (including ITO Services) under this Agreement:

(a) in an independent, fair, and nondiscriminatory manner; and

(b) in accordance with:

(i) any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition ("Good Utility Practice"). Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 2 14(a)(4);

(ii) the terms and conditions of the OATT;

(iii) all applicable laws and the requirements of federal and state regulatory authorities, including the Kentucky Public Service Commission ("KPSC"), Department of Energy ("DOE"), FERC, NERC, SERC, and the North American Electric Standards Board ("NAESB") (collectively, "Regulatory Authorities"); and in fulfilling this requirement in this subsection (iii), TranServ will cooperate with all reasonable requests by Company for information, interviews with TranServ personnel, or other support that may be needed to investigate possible FERC, NERC or other compliance violations or prepare for or respond to compliance-related audits, self-certifications, and other inquiries by Regulatory Authorities (whether internal or external); and

(iv) any methodologies, processes, or procedures relating to ITO

Services which Company may develop and which Company determines are necessary or appropriate to ensure safe and reliable system operations and compliance with all applicable laws and the applicable requirements of Regulatory Authorities.

1.4 Changes to ITO Services. The Parties agree that all changes to ITO Services resulting from legal and regulatory developments, as well as Company requests, shall be assessed using a change order process. This process will include a written assessment of impacts to ITO Services consistent with Section 5 of Appendix A. Changes will be implemented only after mutual execution of a change document, which may be titled a Change Order or an Amendment. If the Parties are unable to agree on whether a change constitutes a "Minor Change," or a "Major Change," as those terms are used in Section 5 of Appendix A, such Dispute shall be resolved in accordance with Section 3.6.

Section 2 - Independence and Standards of Conduct

2.1 TranServ Personnel. All ITO Services shall be performed by staff members of TranServ ("TranServ Personnel") or TranServ Designees. No TranServ Personnel or TranServ Designee shall also be employed by Company or any of its Affiliates (as defined in FERC's regulations, 18 C.F.R. § 35.34(b)(3) (2011)). TranServ, TranServ Employees, and TranServ Designees shall (i) be Independent of and (ii) shall not discriminate against Company, any of its Affiliates, or any Tariff Participant. For purposes of this Agreement: (a) "Independent" shall mean that TranServ, TranServ Personnel, and any TranServ Designees are not subject to the control of Company, its Affiliates or any Tariff Participant, and have full decision-making authority to perform all ITO Services in accordance with the provisions of this Agreement. Any TranServ Personnel or TranServ Designee owning securities in Company, its Affiliates or any Tariff Participant shall divest such securities within six (6) months of first being assigned to perform such ITO Services, provided that nothing in this Section 2.1 shall be interpreted or construed to preclude any such TranServ Personnel or TranServ Designee from indirectly owning securities issued by Company, its Affiliates or any Tariff Participant through a mutual fund or similar arrangement (other than a fund or arrangement specifically targeted toward the electric industry or the electric utility industry or any segment thereof) under which the TranServ Personnel or the TranServ Designee does not control the purchase or sale of such securities. Participation by any TranServ Personnel or TranServ Designee in a pension plan of Company, its Affiliates or any Tariff Participant shall not be deemed to be a direct financial interest if the plan is a defined-benefit plan that does not involve the TranServ Personnel's or TranServ Designee's ownership of the securities; and (b) "Tariff Participant" shall mean Company Transmission System customers, interconnection customers, wholesale customers, affected transmission providers, any Market Participant (as defined in FERC's regulations, 18 C.F.R. § 35.34(b)(2) (2011)) and similarly qualified third parties within the Company Balancing Authority Area. For the avoidance of doubt, Company shall have no veto authority over the selection of TranServ Personnel or TranServ Personnel matters, including TranServ's appointment of a TranServ Project Manager (as provided in Section 8.2) except that the Company and TranServ hereby agree that TranServ shall be prohibited from hiring current or former Company employees until at least one (1) year subsequent to the Company employee's separation from Company. Likewise, Company is prohibited from hiring current or former TranServ employees until one (1) year subsequent to the TranServ employee's separation from TranServ.

2.2 Standards of Conduct Treatment. All TranServ Personnel and TranServ Designees performing work under this Contract shall be treated, for purposes of the FERC's Standards of Conduct (18 C.F.R. Part 358), as transmission function employees. All restrictions relating to information sharing and other relationships between marketing function employees and transmission function employees, as those terms are defined in the Standards of Conduct, including the non-discrimination requirements contained therein, shall apply to TranServ Personnel and TranServ Designees performing work under this Contract, or likely to become privy to transmission function information. Said TranServ Personnel and TranServ Designees shall participate in any Standards of Conduct training that the Company may request for compliance purposes. TranServ shall provide prompt notice of new TranServ Personnel or TranServ Designees to Company to assure new persons are trained within the first thirty (30) days of their employment with TranServ.

Section 3 - Compensation; Billing and Payment; Performance Review

3.1 Compensation for Services. Company shall pay to TranServ an annual fee for performance of the ITO Services ("Annual Fee"). The Annual Fee (subject to increases or decreases in accordance with Section 5 of Appendix A) shall be $2,479,543.56 for the first Contract Year and shall escalate by one and five/tenths percent (1.5%) of the prior year's Annual Fee for each Contract Year thereafter.

3.2 Out-of-Pocket Costs. Company shall reimburse TranServ for actual out-of-pocket third party costs and expenses, without markup, for (a) regulatory legal support that is reasonably allocable to TranServ's performance of ITO Services, provided that in no event shall Company reimburse TranServ for legal fees associated with any actual or potential Dispute under this Agreement, (b) travel and lodging that are reasonably allocable to TranServ's performance of ITO Services and (c) setting up regular stakeholder meetings (collectively, (a), (b) and (c) are "Out-of-Pocket Costs"); provided, however, that all Out-of-Pocket Costs subject to reimbursement under this Section 3.2 must be reviewed and approved by Company prior to TranServ incurring such expense.

3.3 Payment.

3.4.1 Monthly Payment. TranServ shall deliver to Company monthly invoices by regular mail, facsimile, electronic mail or such other means as the Parties agree. Such invoices shall set forth (i) one-twelfth (1/12) of the Annual Fee for each month in advance, and (ii) any Out-of-Pocket costs incurred during the previous month, provided however, that travel expenses occurring on the last three (3) days of each month may be carried over to future invoices for ease of administration. Company shall make payment of the amount invoiced by wire transfer in immediately available funds to an account specified by TranServ not later than the thirtieth (30th) day after receipt of the invoice, unless such day is not a business day, in which case on the next business day. All such payments shall be deemed made when said wire transfer is received by TranServ. Overdue payments shall accrue interest calculated at the FERC interest rate as defined in 18 C.F.R. §35.19a(2)(iii)(A) (2011) ("FERC Interest Rate").

3.4 Annual Review.

3.4.1 Annual Review. Commencing at the end of each Contract Year, no later than sixty (60) days after the end of each Contract Year, TranServ shall determine and deliver to

Company a calculation of TranServ's actual labor in providing ITO Services for the preceding Contract Year ("Annual Labor"). The Annual Labor calculation shall detail the job title and number of full-time employees assigned to ITO Services, and the number of hours spent in performing ITO Services. The Annual Labor shall also include the hours for any tasks which TranServ outsourced to TranServ Designees.

3.5 Compensation Disputes. Notwithstanding the Dispute resolution provisions in Section 8.3, for any Disputes concerning compensation under this Section 3, Company shall timely file notice of such Dispute with FERC and request that FERC resolve such Dispute. TranServ retains the authority to file notice with FERC of any such Dispute if it so desires. If either Party in good faith disputes any invoice submitted by the other Party pursuant to this Agreement, then the disputing Party (i) shall timely pay the other Party the entire invoiced amount and (ii) shall furnish the other Party with a written explanation specifying the amount of and the basis for the Dispute. Within twenty (20) days after resolution of such Dispute, the Party owing money shall pay the other Party the amount owed, if any, together with interest calculated at the FERC Interest Rate.

Section 4 - Term and Termination

4.1 Term. The initial term of this Agreement shall begin on September 1, 2017 ("Commencement Date"), and shall continue for five (5) years thereafter ("Initial Term"). At the conclusion of the Initial Term, this Agreement shall automatically extend for successive one (1) year terms (each a "Subsequent Term"), unless terminated by either Party in accordance with the terms of this Agreement. Three hundred and sixty (360) days prior to the conclusion of the Initial Term either Party may notify the other, in writing, of a desire to amend terms or pricing of this Agreement for the Subsequent Terms. If such amendment is not agreed upon by both parties 180 days prior to the beginning of the first Subsequent Term, the Amendment shall not automatically extend and will terminate on the later of i) the conclusion of the Initial Term, as defined above, or ii) receipt of the regulatory approvals required under Section 4.5. The Initial Term or any Subsequent Terms are each referred to herein as a "Term." For the purposes of this Agreement, a "Contract Year" shall begin on the Commencement Date or anniversary thereof and conclude twelve (12) months thereafter.

4.2 Termination by Either Party. This Agreement may be terminated by either Party at the end of a Term upon prior one hundred eighty (180) days written notice to the other Party, which termination shall be effective upon the later of (i) one hundred eighty (180) days after the date of such written notice, or (ii) receipt of the regulatory approvals required under Section 4.5.

4.3 Immediate Termination.

4.3.1 Termination for Cause. Subject to Section 4.5, either Party may terminate this Agreement upon prior written notice thereof to the other Party if:

(a) Material Failure or Default. The other Party fails, in any material respect, to comply with, observe or perform, or defaults, in any material respect, in the performance of the terms and conditions of this Agreement, and such failure or default remains uncured for thirty (30) days after written notice thereof, provided that such failure or default is susceptible to cure and the other Party is exercising reasonable diligence to cure such failure or default;

(b) Pattern of Failure. It determines, in its reasonable discretion, that there has been a pattern of failure by the other Party to comply with the standards of performance set forth in Section 1.3.1, whether or not such failure is material;

(c) Gross Negligence, Willful Misconduct or Fraud. The other Party commits gross negligence, willful misconduct or fraud in the performance of its obligations under this Agreement;

(d) Material Misrepresentation. Any representation made by the other Party hereunder shall be false or incorrect in any material respect when made and such misrepresentation is not cured within thirty (30) days of such discovery or written notice thereof, or is incapable of cure;

(e) Bankruptcy. The other Party: (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it; (ii) makes an assignment or any general arrangement for the benefit of creditors; (iii) otherwise becomes bankrupt or insolvent (however evidenced); (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets; or (v) is generally unable to pay its debts as they fall due; or

(f) Dissolution. The other Party dissolves or is dissolved or its legal existence is otherwise terminated.

4.3.2 Immediate Termination Not For Cause. Subject to Section 4.5, Company may terminate this Agreement upon thirty (30) days prior written notice thereof to TranServ if:

(a) Failure to Negotiate Amendment. The Parties are unsuccessful in negotiating an amendment or amendments to this Agreement pursuant to Section 17.9;

(b) Regulatory Changes/Modifications. A Regulatory Authority makes any material changes, modifications, additions, or deletions to this Agreement, unless both Parties agree to such changes, modifications, additions, or deletions;

(c) Failure to Receive Regulatory Approval. Prior to the Commencement Date, FERC rejects this Agreement or Company's selection of TranServ as the ITO;

(d) RTO. Company joins a regional transmission organization ("RTO");or

(e) Extended Force Majeure. A Party is excused because of Force Majeure (as defined in Section 11) for more than thirty (30) days from performing any of its material obligations under this Agreement.

4.4 Termination for Lack of Independence. Subject to Section 4.5, Company may terminate this Agreement upon prior written notice thereof to TranServ if FERC or the KPSC issues a final order that declares that TranServ lacks independence from Company and TranServ cannot obtain independence in a reasonable manner or time period.

4.5 Regulatory Approval. No termination of this Agreement shall be effective until approved by FERC and the KPSC. Notice of termination provided pursuant to Sections 4.3 and 4.4 shall become effective immediately upon approval by FERC and the KPSC.

4.6 Return of Materials. Upon any termination of this Agreement TranServ shall timely and in an orderly manner turn over to Company all materials that were prepared or developed pursuant to this Agreement prior to termination, and return or destroy, at the option of Company, all Data and other information supplied by Company to TranServ or created by TranServ on behalf of Company.

4.7 Survival. All provisions of this Agreement which are by their nature or terms intended to survive the termination of this Agreement, including the obligations set forth in Section 7 and Section 10, shall survive termination of this Agreement.

4.8 Compensation for Early Termination.

4.8.1 If Company terminates this Agreement before the end of a Term pursuant to Section 4.3.2 (a), (b), (d) or (e), then Company shall pay to TranServ the Annual Fee(s) through the longer of the end of the Contract Year or for six (6) months subsequent to the date of termination, which fees shall be accelerated hereunder for this purpose, plus any unpaid Out-of-Pocket Costs that TranServ has incurred through the date of any such termination. In the event that this Section 4.8.1 should trigger an acceleration of Annual Fee(s) that would otherwise span multiple years, such fees paid by Company to TranServ shall not include any escalation of one and five/tenths percent (1.5%) as described in Section 3.1 that had not yet been previously applied to the Annual Fee(s).

4.8.2 If Company terminates this agreement before the end of the Term, and such termination is for cause pursuant to Section 4.3.1, then Company shall only be liable for TranServ's Out-of-Pocket Costs incurred pursuant to contracts which extend beyond any early termination date.

4.9 Post-Termination Services. Commencing on the date that any termination becomes effective ("Termination Date") and continuing for up to one hundred eighty (180) days thereafter, TranServ shall (a) provide ITO Services (and any replacements thereof or substitutions therefor), to the extent Company requests such ITO Services to be performed, and (b) cooperate with Company in the transfer of ITO Services (collectively, the "Post-Termination Services") as such services are authorized under a separate agreement between the Parties. TranServ shall, upon Company's request, provide the Post-Termination Services at a cost to be negotiated and mutually agreed to at that time. The quality and level of performance of ITO Services by TranServ shall not diminish. After the expiration of the Post-Termination Services, TranServ shall answer questions from Company regarding ITO Services on an "as needed" basis at TranServ's then-standard billing rates.

4.10 Termination for Guarantee Termination. A guaranty with Open Access Technology International, Inc., in favor of Company and with TranServ as a counterparty was executed (November 29, 2016) (hereinafter "the Guaranty"). Subject to Section 4.5, Company may terminate this Agreement if the Guaranty is terminated and TranServ does not provide a replacement Guaranty determined, by Company, to be satisfactory.

Section 5 - Data Management and Intellectual Property

5.1 Supply of Data. During the Term, Company shall supply to TranServ, and/or grant TranServ access to all Data that TranServ requests and that TranServ believes is necessary to perform its duties and obligations under this Agreement, including ITO Services. The Parties shall agree upon the initial format and manner in which such Data shall be provided. For purposes of this Agreement, "Data" means all information, text, drawings, diagrams, models, images or sounds which are embodied in any electronic or tangible medium and which (a) are supplied or in respect of which access is granted to TranServ by Company under this Agreement, which shall be Company's Data, (b) are prepared, stored or transmitted by TranServ solely on behalf of Company, which shall be Company's Data; or (c) are compiled by TranServ by aggregating Data owned by Company and Data owned by third parties, which shall be TranServ's Data.

5.2 Property of Each Party. Each Party acknowledges that the other Party's Data and the other Party's software, base data models and operating procedures for software or base data models ("Processes") are the property of such other Party and agrees that it will do nothing inconsistent with such ownership, including preserving all intellectual property and/or proprietary rights in such other Party's Data and Processes as provided in Section 6.

5.3 Data Integrity. Each Party shall reasonably assist the other Party in establishing measures to preserve the integrity and prevent any corruption or loss of Data, and the Parties shall reasonably assist each other in the recovery of any corrupted or lost Data. Each Party shall reasonably retain and preserve any of the other Party's Essential Data that are supplied to it during the Term. "Essential Data" means any Data that is reasonably required to perform ITO Services under this Agreement and that must be retained and preserved according to any applicable law, regulation, reliability criteria, or Good Utility Practice. Each Party shall exercise commercially reasonable efforts to preserve the integrity of the other Party's Data that are supplied to it during the Term, in order to prevent any corruption or loss of the other Party's Data.

5.4 Confidentiality. Each Party's Data shall be treated as Confidential Information in accordance with the provisions of Section 10.

Section 6 - Intellectual Property.

6.1 Ownership. All inventions, discoveries, processes, methods, designs, drawings, blueprints, information, works of authorship, or the like, whether or not patentable or copyrightable (collectively, "Intellectual Property"), which TranServ first conceives, develops, or begins to develop, either alone or in conjunction with Company or others, with respect to ITO Services under this Agreement, shall be jointly owned by Company and TranServ, and each party shall have the right to use such intellectual property unless specifically otherwise specified on a change document hereunder.

6.2 Royalties and License Fees. Unless the Parties otherwise agree in writing, TranServ shall procure and pay all royalties and license fees which may be payable on account of ITO Services or any part thereof. In case any part of ITO Services is held in any suit to constitute infringement and its use is enjoined, TranServ within a reasonable time shall, at the election of Company and as Company's exclusive remedy hereunder, either (a) secure for Company the perpetual right to continue the use of such part of ITO Services by procuring for Company a royalty-free license or such other permission as will enable TranServ to secure the suspension of any injunction, or (b) replace at TranServ's own expense such part of ITO Services with a non-infringing part or modify it so that it becomes non-infringing (in either case with changes in functionality that are acceptable to Company).

Section 7 - Indemnification and Limitation of Liability

7.1 Company Indemnification. Subject to the limitations specified in Section 7.6, Company shall indemnify, release, defend, reimburse and hold harmless TranServ and its directors, officers, employees, principals, representatives and agents (collectively, the "TranServ Indemnified Parties") from and against any and all third party claims (including claims of bodily injury or death of any person or damage to real and/or tangible personal property), demands, liabilities, losses, causes of action, awards, fines, penalties, litigation, administrative proceedings and investigations, costs and expenses, and attorney fees, (each, an "Indemnifiable Loss") asserted against or incurred by any of the TranServ Indemnified Parties arising out of, resulting from or based upon TranServ performing its obligations pursuant to this Agreement, provided, however, that in no event shall Company be obligated to indemnify, release, defend, reimburse or hold harmless the TranServ Indemnified Parties from and against any Indemnified Loss which is caused by the negligence, the gross negligence or willful misconduct of any TranServ Indemnified Party.

7.2 TranServ Indemnification. Subject to the limitations specified in Section 7.6, TranServ shall indemnify, release, defend, reimburse and hold harmless Company and its directors, officers, employees, principals, representatives and agents (collectively, the "Company Indemnified Parties") from and against any and all Indemnifiable Losses asserted against or incurred by any of the Company Indemnified Parties arising out of, resulting from or based upon TranServ's or a TranServ Designee's negligence, gross negligence, or willful misconduct, provided, however, that in no event shall TranServ be obligated to indemnify, release, defend, reimburse or hold harmless any Company Indemnified Parties from and against any Indemnified Loss which is caused by the negligence, gross negligence or willful misconduct of any Company Indemnified Party.

7.3 Regulatory Indemnification. Subject to the limitations specified in Section 7.6, TranServ shall indemnify, release, defend, reimburse and hold harmless any Company Indemnified Parties from and against all regulatory penalties and sanctions (including penalties or sanctions levied by a Regulatory Authority) arising out of, resulting from or based upon TranServ breach of this Agreement, specifically including Section 1.3.1 hereto, provided, however, that in no event shall TranServ be obligated to indemnify, release, defend, reimburse or hold harmless any Company Indemnified Parties from and against any penalty or sanction which is caused by the gross negligence or willful misconduct of any Company Indemnified Party.

7.4 Cooperation Regarding Claims. If an Indemnified Party (which for purposes of this Section 7.4 shall mean an TranServ Indemnified Party or a Company Indemnified Party) receives notice or has knowledge of any Indemnifiable Loss that may result in a claim for indemnification by such Indemnified Party against an Indemnifying Party (which for purposes of this Section 7.4 shall mean Company or TranServ) pursuant to this Section 7, such Indemnified Party shall as promptly as possible give the Indemnifying Party written notice of such Indemnifiable Loss, including a reasonably detailed description of the facts and circumstances relating to such Indemnifiable Loss, a complete copy of all notices, pleadings and other papers related thereto, and in reasonable detail the basis for its claim for indemnification with respect thereto. Failure to promptly give such written notice or to provide such information and documents shall not relieve the Indemnifying Party from the obligation hereunder to respond to or defend the Indemnified Party against such Indemnifiable Loss unless and only to the extent such failure shall materially diminish the ability of the Indemnifying Party to respond to or to defend the Indemnified Party against such Indemnifiable Loss. Except for indemnification for penalties and sanctions under Section 7.3, the Indemnifying Party, upon its acknowledgment in writing of its obligation to indemnify the Indemnified Party in accordance with this Section 7, shall be entitled to assume the defense or to represent the interest of the Indemnified Party with respect to such Indemnifiable Loss, which shall include the right to select and direct legal counsel and other consultants, appear in proceedings on behalf of such Indemnified Party and to propose, accept or reject offers of settlement, all at its sole cost. If and to the extent that the defense or settlement of any Indemnifiable Loss is reasonably likely to involve injunctive, equitable or prospective relief or materially and adversely affect the Indemnified Party's business or operations other than as a result of money damages or other money payments assumed by the Indemnifying Party, then such defense or settlement will be subject to the reasonable approval of the Indemnified Party. Nothing herein shall prevent an Indemnified Party from retaining its own legal counsel and other consultants and participating in its own defense at its own cost and expense.

7.5 Release and Indemnification Regarding Liens. TranServ hereby releases and/or waives for itself and its successors in interest, and for all TranServ Designees and their successors in interest, any and all claims or right of mechanics or any other type of lien to assert and/or file upon Company's or any other party's property or any part thereof as a result of performing ITO Services. TranServ shall execute and deliver to Company such documents as may be required by applicable laws (*i.e.*, partial and/or final waivers of liens and/or affidavits of indemnification) to make this release effective and shall give all required notices to TranServ Designees with respect to ensuring the effectiveness of the foregoing releases against those parties. TranServ shall secure the removal of any lien that TranServ has agreed to release in this Section 7.5 within five (5) working days of receipt of written notice from Company to remove such lien. If not timely removed, Company may remove the lien and charge all costs and expenses including legal fees (for inside and/or outside legal counsel) to TranServ including, without limitation, the costs of bonding off such lien. Company, in its sole discretion, expressly reserves the right to off-set and/or retain any reasonable amount due to TranServ from payment of any one or more of TranServ's invoices upon Company having actual knowledge of any threatened and/or filed liens and/or encumbrances that may be asserted and/or filed by any TranServ Designee and/or third party with respect to the ITO Services, with final payment being made by Company only upon verification that such threatened and/or filed liens and/or encumbrances have been irrevocably satisfied, settled, resolved and/or released (as applicable), and/or that any known payment disputes concerning the ITO Services involving TranServ and any TranServ Designees have been resolved so that no actions, liens and/or encumbrances of any kind or nature will be filed against Company and/or Company's property.

7.6 Limitation of Liability. Other than as provided in Section 7.3, neither Party shall be liable to the other for any special, punitive, or consequential damages arising out of ITO Services, even if advised of the possibility of such damages. Company agrees that ITO Services are not consumer goods for purposes of international, U.S. Federal or U.S. state warranty laws. Indemnification pursuant to Sections 7.1, 7.2, and 7.3, as well as any direct damages to Company arising out of a material breach of this Agreement shall be limited in the aggregate to the total amount of fees actually paid by Company to TranServ under this Agreement through the date that any penalty or judgment is assessed.

Section 8 - Contract Managers; Dispute Resolution

8.1 Company Contract Manager. Company shall appoint an individual (the "Company Contract Manager") who shall serve as the primary Company representative under this Agreement. The Company Contract Manager shall (a) have overall responsibility for managing and coordinating the performance of Company's obligations under this Agreement, and (b) be authorized to act for and on behalf of Company with respect to all matters relating to this Agreement. Notwithstanding the foregoing, the Company Contract Manager may, upon written notice to TranServ, delegate such of his or her responsibilities to other Company employees, as the Company Contract Manager deems appropriate.

8.2 TranServ Project Manager. TranServ shall appoint, among TranServ Personnel, an individual (the "TranServ Project Manager") who shall serve as the primary TranServ representative under this Agreement. The TranServ Project Manager shall have overall responsibility for managing and coordinating the performance of TranServ obligations under this Agreement. Notwithstanding the foregoing, the TranServ Project Manager may, upon written notice to Company, delegate such of his or her responsibilities to other TranServ Personnel, as the TranServ Project Manager deems appropriate.

8.3 Resolution of Disputes. Any dispute, claim or controversy between the Parties arising out of or relating to this Agreement (each, a "Dispute") shall be resolved in accordance with the procedures set forth in this Section 8.3; provided, however, that this Section 8.3 shall not apply to Disputes arising from or relating to (a) the amount of compensation to be paid by Company pursuant to Section 3.1, which shall be resolved pursuant to Section 3.6, (b) confidentiality or intellectual property rights, in which case either Party shall be free to seek available legal or equitable remedies, or (c) alleged violations of the OATT, in which case either Party shall be free to bring the Dispute to FERC.

8.3.1 Notice of Dispute. Each Party shall provide written notice to the other party of any Dispute, including a description of the nature of the Dispute.

8.3.2 Dispute Resolution by Contract Managers. Any Dispute shall first be referred to the Company Contract Manager and TranServ Project Manager, who shall negotiate in good faith to resolve the Dispute.

8.3.3 Dispute Resolution by Executive Management Representatives. If the Dispute is not resolved within fifteen (15) calendar days of being referred to the Company Contract Manager and the TranServ Project Manager pursuant to Section 8.3.2, then each Party shall have five (5) calendar days to appoint an executive management representative who shall negotiate in good faith to resolve the Dispute.

8.3.4 Binding Arbitration. If the Dispute is not resolved within ten (10) calendar days of being referred to executive management representatives, and the amount in dispute or potential damages exceeds $250,000 USD, the Parties shall proceed in good faith to submit immediately the matter to binding arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("AAA") as they may be amended from time to time (the "Arbitration Rules") subject to the following conditions:

(a) The Parties shall give due consideration to using the Expedited Procedures under the Arbitration Rules in any case in which no disclosed claim or counterclaim exceeds $75,000, exclusive of interest and arbitration fees and costs.

(b) The Parties agree that three arbitrators will be used. Each Party will directly appoint one arbitrator of its choosing from a list of members from the National Roster (as that term is used in the Arbitration Rules) provided by the AAA pursuant to R-12, within ten (10) Days after receipt of such names. The two arbitrators so appointed shall select a third arbitrator from the National Roster to serve as chairperson.

(c) "Baseball" arbitration (in which each Party presents a proposed award or resolution and the actual award must be one of the two submitted), or close variants thereof, shall not be used.

(d) The arbitrators have no authority to appoint or retain expert witnesses for any purpose unless agreed to by the Parties.

(e) All arbitration fees and costs shall be borne equally, regardless of which Party prevails.

(f) Each Party shall bear its own costs of legal representation and witness expenses, unless the arbitrator(s) determines that one Party should bear some or all of the costs of legal representation and witness expenses of the other Party.

(g) The Parties waive any right of appeal or recourse to any court except to compel arbitration, to compel the appointment of arbitrators, to stay judicial proceedings pending arbitration, for an injunction pending determination by the arbitrators, for disqualification of arbitrators, for aid in furtherance of arbitration, to confirm the award, to enforce any judgment confirming the award, or in circumstances of fraud or failure to disclose information or documents required by the arbitrators.

(h) The decision or award of a majority of the arbitrators shall govern. The decision or award of the arbitrators shall be final and binding upon the Parties to the same extent and to the same degree as if the matter had been adjudicated by a court of competent jurisdiction and shall be enforceable under the Federal Arbitration Act and applicable states' laws.

8.3.5 Rights and Remedies. If the Dispute is not resolved within ten (10) calendar days of being referred to executive management representatives, and the amount in dispute or potential damages does not exceed $250,000 USD, each Party is free to pursue any rights or remedies it may have at law or equity.

8.4 Rights Under FPA Unaffected. Except as provided in Section 17.2 relating to the variation or amendment of this Agreement, nothing in this Agreement is intended to limit or abridge any rights that Company may have to file or make application before FERC under Section 205 of the Federal Power Act to revise any rates, terms or conditions of the OATT.

8.5 Statute of Limitations; Continued Performance. The Parties agree to waive the applicable statute of limitations during the period of time that the Parties are seeking to resolve a Dispute pursuant to Section 8.3, and the statute of limitations shall be tolled for such period. The Parties shall continue to perform their obligations under this Agreement during the resolution of a Dispute.

Section 9 - Insurance

9.1 TranServ's Insurance Obligation. During the Term, TranServ shall provide and maintain, and shall require TranServ Designees to provide and maintain, the following insurance (and, except with regard to Workers' Compensation, naming Company as additional insured and waiving rights of subrogation against Company and Company's insurance carrier(s)), and TranServ shall submit evidence of such coverage(s) of TranServ and any TranServ Designees to Company prior to the start of ITO Services. Furthermore, TranServ shall notify Company, prior to the commencement of ITO Services, of any threatened, pending and/or paid off claims to third parties, individually or in the aggregate, which otherwise affects the availability of the limits of such coverage(s) inuring to the benefit of Company as hereinafter specified:

9.1.1 Workers' Compensation and Employer's Liability Policy, which shall include provisions required by applicable law in the jurisdiction of location of workers.

9.1.2 Employer's Liability (Coverage B) with limits of One Million Dollars ($1,000,000) Bodily Injury by Accident, each Accident, $1,000,000 Bodily Injury by Disease, each Employee, and including:

(a) a thirty (30) day cancellation clause; and

(b) broad form all states endorsement.

9.1.3 Commercial General Liability Policy, which shall have minimum limits of One Million Dollars ($1,000,000) each occurrence; One Million Dollars ($1,000,000) Products/Completed Operations Aggregate each occurrence; One Million Dollars ($1,000,000) Personal and Advertising Injury each occurrence, in all cases subject to Two Million Dollars ($2,000,000) in the General Aggregate for all such claims, and including:

(a) a thirty (30) day cancellation clause;

(b) Blanket Written Contractual Liability to the extent covered by the policy against liability assumed by TranServ under this Agreement; and

(c) Broad Form Property Damage.

9.1.4 Commercial Automobile Liability Insurance covering the use of all owned, non-owned, and hired automobiles, with a bodily injury, including death, and property damage combined single minimum limit of One Million Dollars ($1,000,000) each occurrence with respect to TranServ's vehicles assigned to or used in performance of ITO

Services under this Agreement.

9.1.5 Umbrella/Excess Liability Insurance with minimum limits of Two Million Dollars ($2,000,000) per occurrence; Two Million Dollars ($2,000,000) aggregate, to apply to employer's liability, commercial general liability, and automobile liability.

9.1.6 To the extent applicable, if engineering or other professional services will be separately provided by TranServ as specified in Appendix A, then Professional Liability Insurance with limits of Three Million Dollars ($3,000,000) per occurrence and Three Million Dollars ($3,000,000) in the aggregate, which insurance shall be either on an occurrence basis or on a claims made basis (with a retroactive date satisfactory to Company).

9.2 Quality of Insurance Coverage. The above policies to be provided by TranServ shall be written by insurance companies which are both licensed to do business in the state where ITO Services will be performed and either satisfactory to Company or having a Best Rating of not less than "A-". These policies shall not be materially changed or canceled except with thirty (30) days written notice to Company from TranServ and the insurance carrier. Evidence of coverage, notification of cancellation or other changes shall be mailed to: Attention: Manager, Supply Chain, LG&E and KU Services Company, P.O. Box 32020, Louisville, Kentucky 40232.

9.3 Implication of Insurance. Company reserves the right to request and receive a summary of coverage of any of the above policies or endorsements; however, Company shall not be obligated to review any of TranServ's certificates of insurance, insurance policies, or endorsements, or to advise TranServ of any deficiencies in such documents. Any receipt of such documents or their review by Company shall not relieve TranServ from or be deemed a waiver of Company's rights to insist on strict fulfillment of TranServ's obligations under this Agreement.

9.4 Other Notices. TranServ shall provide written notice of any accidents or claims in connection with ITO Services or this Agreement to Company's Manager, Risk Management at LG&E and KU Services Company, P.O. Box 32030, Louisville, Kentucky 40232.

Section 10 - Confidentiality

10.1 Definition of Confidential Information. For purposes of this Agreement, "Confidential Information" shall mean, in respect of each Party, all information and documentation of such Party, whether disclosed to or accessed by the other Party in connection with this Agreement and which is identified as Confidential Information, or which otherwise would be treated as confidential by the recipient, including confidential information provided by third-parties; provided, however, that the term "Confidential Information" shall not include information that: (a) is independently developed by the recipient, as demonstrated by the recipient's written records, without violating the disclosing Party's proprietary rights; (b) is or becomes publicly known (other than through unauthorized disclosure); (c) is disclosed by the owner of such information to a third party free of any obligation of confidentiality; (d) is already known by the recipient at the time of disclosure, as demonstrated by the recipient's written records, and the recipient has no obligation of confidentiality other than pursuant to this Agreement or any confidentiality agreements between the Parties entered into before the Commencement Date; or (e) is rightfully received by a Party free of any obligation of confidentiality.

10.2 Protection of Confidential Information. All Confidential Information shall be held in confidence by the recipient to the same extent and in at least the same manner as the recipient protects its own Confidential Information, and such Confidential Information shall be used only for purposes of performing obligations under this Agreement. Except as otherwise provided in Section 10.3, neither Party shall disclose, publish, release, transfer or otherwise make available Confidential Information of, or obtained from, the other Party in any form to, or for the use or benefit of, any person or entity without the owner of such information's prior written consent. Each Party shall be permitted to disclose relevant aspects of the other Party's Confidential Information to its officers, directors, agents, professional advisors, contractors, subcontractors (including TranServ Designees) and employees and to the officers, directors, agents, professional advisors, contractors, subcontractors and employees of its Affiliates (collectively, "Representatives"), to the extent that such disclosure is reasonably necessary for the performance of its duties and obligations or the determination, preservation or exercise of its rights and remedies under this Agreement; provided, however, that the recipient shall take all reasonable measures to ensure that Confidential Information is not disclosed or duplicated in contravention of the provisions of this Agreement by such officers, directors, agents, professional advisors, contractors, subcontractors and employees. Recipient agrees to be liable for the wrongful actions of its Representatives under this Section 10.2. The obligations in this Section 10 shall not restrict any disclosure pursuant to any Regulatory Authority if such release is necessary to comply with valid laws, governmental regulations or final orders of regulatory bodies or courts; provided that, other than in respect of disclosures pursuant to Section 10.3, the recipient shall give prompt written notice to the disclosing Party in reasonable time to exercise whatever legal rights the disclosing Party may have to prevent or limit such disclosure. Further, the recipient shall cooperate with the disclosing Party in preventing or limiting such disclosure.

10.3 Regulatory Requests for Confidential Information. Notwithstanding anything in this Section 10 to the contrary, if a Regulatory Authority or its staff, during the course of an investigation or otherwise, requests Confidential Information from TranServ, TranServ shall provide the requested Confidential Information to the requesting Regulatory Authority or its staff within the time provided for in the request for information. In providing the Confidential Information to a Regulatory Authority or its staff, TranServ shall, consistent with 18 C.F.R. § 388.112 (2011) or any other applicable confidentiality regulation, request that the Confidential Information be treated as confidential and non-public by the Regulatory Authority and its staff and that the information be withheld from public disclosure. TranServ shall notify Company when it is notified by the Regulatory Authority or its staff that a request for public disclosure of, or decision to publicly disclose, Confidential Information has been received, at which time either TranServ or Company may respond before such Confidential Information is made public, pursuant to 18 C.F.R. § 388.112 or the applicable confidentiality regulation.

Section 11 - Force Majeure.

11.1 Force Majeure. Neither Party shall be liable to the other Party for any failure or delay of performance hereunder due to an event which (i) is not reasonably foreseeable or within the reasonable control of the Party claiming Force Majeure (the "Claiming Party") or any Person over which the Claiming Party has control, (ii) was not caused by the acts, omissions, negligence, fault or delays of the Claiming Party or any person over whom the Claiming Party has control, (iii) is not an act, event or condition the risks or consequences of which the Claiming Party has expressly agreed to assume pursuant to this Agreement, and (iv) by the prompt exercise of due diligence, the

Claiming Party is unable to overcome or avoid or cause to be avoided (collectively, (i) - (iv) are "Force Majeure"). Force Majeure shall include: acts of God; acts of the public enemy, war, hostilities, invasion, insurrection, riot, civil disturbance, or order of any competent civil or military government; explosion or fire; strikes or lockouts or other industrial action (excluding those of the Claiming Party unless such action is part of a wider industrial dispute materially affecting other employers); labor or material shortage; malicious acts, vandalism or sabotage; action or restraint by court order of any public or governmental authority (so long as the Claiming Party has not applied for or assisted in the application for, and has opposed where and to the extent reasonable, such government action). Neither Party shall be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to Force Majeure, except for the obligation to pay any amount when due, provided that the Claiming Party:

11.1.1 gives prompt written notice to the other Party of the event or circumstance giving rise to the event of Force Majeure;

11.1.2 affords the other Party reasonable access to information about the event or circumstances giving rise to the event of Force Majeure;

11.1.3 takes commercially reasonable steps to restore its ability to perform its obligations hereunder as soon as reasonably practicable, provided that the Claiming Party shall not be obligated to take any steps that are not otherwise in accordance with Good Utility Practice; and

11.1.4 exercises commercially reasonable efforts to perform its obligations hereunder.

Section 12 - Reporting; Audit.

12.1 Regulatory Reporting.

12.1.1 TranServ shall have the authority to report in writing to FERC in respect of any compensation-related Dispute that arises between TranServ and Company pursuant to Section 3.6.

12.1.2 TranServ shall report in writing to FERC every six (6) months (commencing on the six (6) month anniversary of the Commencement Date and every six (6) months thereafter during the Term) in respect of (a) any concerns expressed by stakeholders and TranServ's response to same and (b) any issues or OATT provisions that hinder TranServ from performing its duties and obligations under this Agreement and the OATT.

12.1.3 In addition to the reports provided for above, TranServ shall make such other reports to Regulatory Authorities as may be required by applicable law and regulations or as may be requested by such Regulatory Authorities.

12.2 Books and Records. TranServ shall maintain full and accurate books and records pertinent to this Agreement, and TranServ shall maintain such books and records for a minimum of five (5) years following the expiration or early termination of this Agreement or longer if necessary to resolve a pending Dispute. Company will have the right, at reasonable times and under reasonable conditions, to inspect and audit, or have an independent third party inspect and audit, TranServ's operations, books, and records (a) to ensure compliance with this Agreement, including TranServ's performance of ITO Services in accordance with Section 1.3.1, (b) to verify any cost claims or other amounts due hereunder, and (c) to validate TranServ's internal controls with respect to the performance of ITO Services. TranServ shall maintain an audit trail, including all original transaction records and timekeeping records, of all financial and non-financial transactions and activities resulting from or arising in connection with this Agreement as may be necessary to enable Company or the independent third party, as applicable, to perform the foregoing activities. Company shall be responsible for any costs and expenses incurred in connection with any such inspection or audit, unless such inspection or audit discovers that Company was charged inappropriate or incorrect costs and expenses, in which case, TranServ shall be responsible for a percentage of the costs and expenses incurred in connection with such inspection or audit equal to the percentage variance by which Company was charged inappropriate or incorrect costs and expenses. TranServ shall provide reasonable assistance necessary to enable Company or an independent third party, as applicable, to perform the foregoing activities and shall not be entitled to charge Company for any such assistance. Amounts incorrectly or inappropriately invoiced by TranServ to Company, whether discovered prior to or subsequent to payment by Company, shall be adjusted or reimbursed to Company by TranServ within twenty (20) days of notification by Company to TranServ of the error in the invoice.

Section 13 - Independent Contractor

13.1 TranServ, in performing ITO Services, shall not act as an agent or employee of Company, but shall be and act as an independent contractor and, except as established in Section 1.3.1, shall be free to perform ITO Services by such methods and in such manner as TranServ may choose, doing everything necessary to perform such ITO Services properly and safely and having supervision over and responsibility for the safety and actions of its employees and the suitability of its equipment. TranServ Personnel and TranServ Designees shall not be deemed to be employees and/or agents of Company. TranServ agrees that if any portion of ITO Services are subcontracted to TranServ Designees, such TranServ Designees shall be bound by and observe the conditions of this Agreement to the same extent as required of TranServ. In such event, Company strongly encourages the use of Minority Business Enterprises, Women Business Enterprises and Disadvantaged Business Enterprises, as defined under federal law and as certified by a certifying agency that Company recognizes as proper.

13.2 Notwithstanding any provision in this Agreement to the contrary, unless approved in writing by Company, TranServ shall not (and shall not permit any TranServ Personnel or TranServ Designee to):

13.2.1 Sell, lease, pledge, mortgage, encumber, convey, or make any license, exchange or other transfer, assignment or disposition of any property or assets of Company;

13.2.2 Enter into, amend, terminate, modify or supplement any contract or agreement (including any labor or collective bargaining agreement) on behalf, or in the name, of Company;

13.2.3 Except upon the approval of Company or pursuant to the direction of Company, take any action that would, to TranServ's knowledge: (a) invalidate any warranty that runs to Company under any contract or agreement; or (b) release any person or entity from its obligations under any contract or agreement with Company;

13.2.4 Make any warranty or representation on behalf of Company;

13.2.5 Except as contemplated under Section 7.4, settle, compromise, assign, pledge, transfer, release or consent to the compromise, assignment, pledge, transfer or release of any claim, suit, debt, demand or judgment against or due by Company, or submit any such claim, dispute or controversy to arbitration or judicial process, or stipulate in respect thereof to a judgment, or consent to the same;

13.2.6 Pledge the credit of Company in any way in respect of any commitments for which it has not received express written authorization from Company; or

13.2.7 Engage in any other transaction on behalf of Company not permitted under this Agreement.

Section 14 - Taxes.

Each Party shall be responsible for the payment of its own taxes, including taxes based on its net income, employment taxes of its employees, taxes on any property it owns or leases, and sales, use, gross receipts, excise, value-added or other transaction taxes. Sales and/or use taxes, that become applicable to services performed within Minnesota, shall be added to TranServ fees and compensation otherwise herein described.

Section 15 - Notices.

15.1 Notices. All notices, requests, consents and other communications required or permitted hereunder shall be in writing, signed by the Party giving such notice or communication, and shall be deemed given: (a) upon receipt, when mailed by U.S. certified mail, postage prepaid, return receipt requested; or (b) upon the next business day, when sent by overnight delivery, postage prepaid using a recognized courier service.

If to Company:

LG&E/KU
VP, Transmission
220 West Main St
PO Box 32010
Louisville, KY 40232

If to TranServ:

TranServ International, Inc.
Contracts Administration
3660 Technology Drive NE
Minneapolis, MN 55418

15.2 Changes. Either Party may, from time to time, change the names, addresses, facsimile numbers or other notice information set out in Section 15.1 by notice to the other Party in accordance with the requirements of Section 15.1.

Section 16 - Personnel and Work Conditions; NERC Requirements.

16.1 Applicable Laws and Safety. TranServ agrees to protect TranServ Personnel and TranServ Designees and be responsible for their performance of the ITO Services, and to protect Company's facilities, property, employees and third parties from damage or injury. TranServ shall at all times be solely responsible for complying with any and all applicable laws and facility rules relating to health and safety, in connection with ITO Services and for obtaining (but only as approved by Company) all permits and approvals necessary to perform ITO Services. Without limiting the foregoing, TranServ agrees to strictly abide by and observe all standards of the Occupational Safety & Health Administration ("OSHA") which are applicable to ITO Services, as well as Company's Contractor Code of Business Conduct and Company's Contractor/Subcontractor Safety Policy which are both hereby incorporated by reference (Contractor hereby acknowledges receipt of a copy of such Company's Contractor Code of Business Conduct and Company's Contractor/Subcontractor Safety Policy) and any other rules and regulations of the Company, all of which are provided to TranServ in writing and incorporated herein by reference. TranServ also agrees to review in good faith and execute any amendments and/or modifications that may be issued in the future by Company from time to time, with respect to Company's Contractor Code of Business Conduct and/or any of its related policies which are the subject of this Section 16, provided however, that TranServ shall not be obliged by such requirement if the requirements conflicts with an alternate regulatory code of conduct imposed on TranServ. In the event TranServ subcontracts any of ITO Services to a TranServ Designee, TranServ shall notify Company in writing of the identity of TranServ Designee before utilizing TranServ Designee. TranServ shall require any TranServ Designees to complete the safety and health questionnaire and checklists provided by Company and shall provide a copy of such documents to Company upon request. TranServ shall conduct, and require such TranServ Designees to conduct, safety audits and job briefings during performance of ITO Services as applicable. In the event such TranServ Designee has no procedure for conducting safety audits and job briefings, TranServ shall include TranServ Designee in its safety audits and job briefings. All applicable safety audits shall be documented in writing by TranServ and such TranServ Designees. TranServ shall provide documentation of any and all audits identifying safety deficiencies and concerns and corrective action taken as a result of such audits to Company semi-monthly. TranServ further specifically acknowledges, agrees and warrants that TranServ has complied, and shall at all times during the term of this Agreement, comply in all respects with all laws, rules and regulations relating to the employment authorization of TranServ Personnel including, but not limited to, the Immigration Reform and Control Act of 1986, as amended, and the Illegal Immigration Reform and Immigrant Responsibility Act of 1996, as amended, whereby TranServ certifies to Company that TranServ has (a) properly maintained, and shall at all times during the term of this Agreement properly maintain all records required by Immigration and Customs Enforcement, such as the completion and maintenance of the Form I-9 for each TranServ employee; (b) that TranServ maintains and follows an established policy to verify the employment authorization of TranServ Personnel; (c) that TranServ has verified the identity and employment eligibility of all TranServ Personnel in compliance with all applicable laws; and (d) that TranServ is without knowledge of any fact that would render any TranServ Personnel or TranServ Designee ineligible to legally work in the United States. TranServ further acknowledges, agrees and warrants that any TranServ Designee shall be required to agree to these same terms as a condition to being awarded any subcontract for such ITO Services.

16.2 Hazards and Training. TranServ shall furnish adequate numbers of trained, qualified, and experienced TranServ Personnel suitable for performance of ITO Services. Such TranServ Personnel shall be skilled and properly trained to perform ITO Services and recognize all hazards associated with ITO Services. Without limiting the foregoing, TranServ shall participate in any safety orientation or other of Company's familiarization initiatives related to safety and shall strictly comply with any monitoring initiatives as determined by Company.

16.3 Drug and Alcohol. TranServ shall develop and strictly comply with any and all drug and alcohol testing requirements as required by applicable laws. TranServ shall provide Company with a copy of its drug and alcohol testing requirements.

16.4 NERC Reliability Standards. The following additional provisions shall apply to the extent TranServ's performance of ITO Services requires physical or electronic access to areas or assets which are located within physical security perimeters as defined by NERC's Reliability Standards for the Bulk Electric Systems of North America (collectively, the "NERC Standards"), including without limitation any Company data center or control center. In the event of TranServ's non-compliance with the NERC Standards referenced in this Section 16.4, Company shall notify TranServ in writing of the non-compliance and specify appropriate remedial actions.

16.4.1 Information Protection. Without compromising the confidentiality provisions in Section 10, TranServ shall at all times comply with the Company's information protection program(s) as defined by CIP-003, R4. Among the information protected by this program are: (i) all operational procedures; (ii) lists of critical cyber assets; (iii) network topology or similar diagrams; (iv) floor plans of computing centers that contain critical cyber assets; (v) equipment layouts of critical cyber assets; (vi) disaster recovery plans; (vii) incident response plans; and (viii) security configuration information. TranServ shall protect this protected information from disclosure consistent with the program.

16.4.2 Access Revocation. TranServ shall immediately advise appropriate Company's management if any TranServ Personnel or TranServ Designees who have key card access to a Company restricted area or electronic access to a protected system no longer require such access.

16.4.3 Training. If any TranServ Personnel require key card access to a Company restricted area or electronic access to a protected system, TranServ shall ensure that such personnel complete, and retake as requested, all necessary NERC training as requested by Company.

16.4.4 Personnel Risk Assessment. If any TranServ Personnel require key card access to a Company restricted area or electronic access to a protected system, TranServ shall ensure that Company receives necessary waivers and information from TranServ Personnel to complete, and repeat as necessary, such background checks as requested by Company.

16.4.5 Continuing Obligations. TranServ further acknowledges that its compliance with the NERC Standards referenced in this Section 16.4 is a continuing obligation during and after the Term. Upon written notice to TranServ, Company shall have the absolute right to audit and inspect any and all information regarding TranServ's compliance with this Section 16.4, and/or to require confirmation of the destruction of any documentation received from or regarding Company. TranServ is encouraged to contact Company's Compliance Department pursuant to Section 16.5 to ensure TranServ understands and complies with this Section 16.4.

16.5 Compliance Department. The Company has a Compliance Department. Should TranServ have actual knowledge of violations of any of the herein stated policies of conduct in this Section 16, or in standards of performance detailed in Section 1.3.1, or have a reasonable basis to believe that such violations have occurred, whether by TranServ Personnel or a TranServ Designee, TranServ has an affirmative obligation to immediately report, at least on an anonymous basis, any such known violations to the Company's Office of Compliance in care of Director, Compliance and Ethics, LG&E/KU Services, 220 West Main Street, Louisville, Kentucky 40202.

16.6 Equal Employment Opportunity. To the extent applicable, TranServ shall comply with all of the following provisions, which are incorporated herein by reference: (i) Equal Opportunity regulations set forth in 41 C.F.R. § 60-1.4(a) and (c), prohibiting employment discrimination against any employee or applicant because of race, color, religion, sex, or national origin; (ii) Vietnam Era Veterans Readjustment Assistance Act regulations set forth in 41 C.F.R. § 60-250.4 relating to the employment and advancement of disabled veterans and Vietnam era veterans; (iii) Rehabilitation Act regulations set forth in 41 C.F.R. § 60-741.4 relating to the employment and advancement of qualified disabled employees and applicants for employment; (iv) the clause known as "Utilization of Small Business Concerns and Small Business Concerns Owned and Controlled by Socially and Economically Disadvantaged Individuals" set forth in 15 USC § 637(d)(3); and (v) the subcontracting plan requirement set forth in 15 USC § 637(d).

Section 17 - Miscellaneous Provisions.

17.1 Governing Law. This Agreement and the rights and obligations of the Parties hereunder shall be governed by and construed in accordance with the laws of the Commonwealth of Kentucky, without giving effect to its conflicts of law rules.

17.2 Amendment. This Agreement shall not be varied or amended unless such variation or amendment is agreed to by the Parties in writing and accepted by applicable Regulatory Authorities. The Parties explicitly agree that neither Party shall unilaterally petition to FERC pursuant to the provisions of Sections 205 or 206 of the Federal Power Act to amend this Agreement or to request that FERC initiate its own proceeding to amend this Agreement. Nothing in this Section 17.2 shall be construed to limit or affect any other rights that the Parties may have as set forth in Section 8.4, the OATT or otherwise.

17.3 Liability of Affiliates. Any and all liabilities of Company and/or its Affiliates under this Agreement shall be several but not joint.

17.4 Publicity. TranServ shall not issue news releases, publicize or issue advertising pertaining to ITO Services or this Agreement without first obtaining the written approval of Company.

17.5 Assignment. Any assignment of this Agreement or any interest herein or delegation of all or any portion of a Party's obligations, by operation of law or otherwise, by either Party without the other Party's prior written consent shall be void and of no effect; provided, however, that consent will not be required for Company to assign this Agreement to an Affiliate or a successor entity that acquires all or substantially all of the operational business assets of the assigning entity whether by merger, consolidation, reorganization, sale, spin-off or foreclosure; provided, further, that such Affiliate or successor entity (a) agrees to assume all obligations hereunder from and after the date of such assignment and (b) has the legal authority and operational ability to satisfy the obligations under this Agreement. As a condition to the effectiveness of such assignment (i) the assignor shall promptly notify the other Party of such assignment, (ii) the Affiliate or successor entity shall provide a confirmation to the other Party of its assumption of assignor's obligations hereunder, and (iii) assignor shall promptly reimburse the other Party, upon receipt of an invoice, for any one-time incremental costs reasonably incurred as a result of such assignment. For the avoidance of doubt, nothing herein shall preclude Company from transferring any or all of its transmission facilities to another entity or disposing of or acquiring any other transmission assets. Notwithstanding anything to the contrary contained in this Section 17.5, TranServ shall be entitled to contract with one or more persons (each, an "TranServ Designee") to perform only those ITO Services which the OATT expressly provides for being performed by a "designee" of TranServ (as opposed to TranServ or TranServ Personnel), provided that TranServ shall not be relieved of any of its obligations, responsibilities or liabilities under this Agreement as a result of contracting with one or more TranServ Designees in accordance with this Section 17.5 and shall be responsible and liable for any ITO Services performed by TranServ Designees.

17.6 No Third Party Beneficiaries. Except as otherwise expressly provided in this Agreement, this Agreement is made solely for the benefit of the Parties and their successors and permitted assigns and no other person shall have any rights, interest or claims hereunder or otherwise be entitled to any benefits under or on account of this Agreement as third party beneficiary or otherwise.

17.7 Waivers. No waiver of any provision of this Agreement shall be effective unless it is signed by the Party against which it is sought to be enforced. The delay or failure by either Party to exercise or enforce any of its rights or remedies under this Agreement shall not constitute or be deemed a waiver of that Party's right thereafter to enforce those rights or remedies, nor shall any single or partial exercise of any such right or remedy preclude any other or further exercise thereof or the exercise of any other right or remedy.

17.8 Enforcement of Rights. Each Party shall have the right to recover from the other Party all expenses, including fees for and expenses of inside and/or outside counsel, arising out of the other Party's breach of this Agreement or any other action to enforce or defend rights hereunder.

17.9 Severability; Renegotiation. The invalidity or unenforceability of any portion or provision of this Agreement shall in no way affect the validity or enforceability of any other portion or provision herein. If any provision of this Agreement is found to be invalid, illegal or otherwise unenforceable, the same shall not affect the other provisions hereof or the whole of this Agreement and shall not render invalid, illegal or unenforceable this Agreement or any of the remaining provisions of this Agreement. If any provision of this Agreement or the application thereof to any person, entity or circumstance is held by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, or if a modification or condition to this Agreement is imposed by such court or regulatory authority, the Parties shall in good faith negotiate such amendment or amendments to this Agreement as will restore the relative benefits and obligations of the Parties immediately prior to such holding, modification or condition.

17.10 Remedies. No remedy conferred by any of the provisions of this Agreement is intended to be exclusive of any other remedy available at law or equity or otherwise. The election of one or more remedies shall not constitute a waiver of the right to pursue any other available remedies.

17.11 Representations and Warranties. Each Party represents and warrants to the other Party as of the date hereof as follows:

17.11.1 Organization. It is duly organized, validly existing and in good standing under the laws of the State in which it was organized, and has all the requisite power and authority to own and operate its material assets and properties and to carry on its business as now being conducted and as proposed to be conducted under this Agreement.

17.11.2 Authority. It has the requisite power and authority to execute and deliver this Agreement and, subject to the procurement of applicable regulatory approvals, to perform its obligations under this Agreement. The execution and delivery of this Agreement by it and the performance of its obligations under this Agreement have been duly authorized by all necessary corporate action required on its part.

17.11.3 Binding Effect. Assuming the due authorization, execution and delivery of this Agreement by the other Party, this Agreement constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency or other similar applicable laws affecting creditors' rights generally, and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

17.11.4 Regulatory Approval. It has obtained or will obtain by the Commencement Date, any and all approvals of, and acceptances for filing by, and has given or will give any notices to, any applicable federal or state authority, including FERC and the KPSC (as applicable), that are required for it to execute, deliver, and perform its obligations under this Agreement.

17.11.5 No Litigation. There are no actions at law, suits in equity, proceedings, or claims pending or, to its knowledge, threatened against it before or by any federal, state, foreign or local court, tribunal, or governmental agency or authority that might materially delay, prevent, or hinder the performance by such entity of its obligations hereunder.

17.11.6 No Violation or Breach. The execution, delivery and performance by it of its obligations under this Agreement do not and shall not: (a) violate its organizational documents; (b) violate any applicable law, statute, order, rule, regulation or judgment promulgated or entered by any applicable federal or state authority, which violation could reasonably be expected to materially adversely affect the performance of its obligations under this Agreement; or (c) result in a breach of or constitute a default of any material agreement to which it is a party.

17.11.7 No Other Warranties. EXCEPT AS PROVIDED IN THIS AGREEMENT, TRANSERV MAKES NO OTHER WARRANTIES OF ANY KIND, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, WARRANTIES OF

MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE.

17.12 Further Assurances. Each Party agrees that it shall execute and deliver such further instruments, provide all information, and take or forbear such further acts and things as may be reasonably required or useful to carry out the purpose of this Agreement and are not inconsistent with the provisions of this Agreement.

17.13 Entire Agreement. This Agreement and the Attachments hereto set forth the entire agreement between the Parties with respect to the subject matter hereof, and supersede all prior agreements, whether oral or written, related to the subject matter of this Agreement. The terms of this Agreement and the Attachments hereto are controlling, and no parole or extrinsic evidence, including to prior drafts and drafts exchanged with any third parties, shall be used to vary, contradict or interpret the express terms and conditions of this Agreement.

17.14 Good Faith Efforts. Each Party agrees that it shall in good faith take all reasonable actions necessary to permit it and the other Party to fulfill their obligations under this Agreement. Where the consent, agreement or approval of any Party must be obtained hereunder, such consent, agreement or approval shall not be unreasonably withheld, delayed or conditioned. Where a Party is required or permitted to act, or omit to act, based on its opinion or judgment, such opinion or judgment shall not be unreasonably exercised, other than where expressly provided for herein. To the extent that the jurisdiction of any federal or state authority applies to any part of this Agreement or the transactions or actions covered by this Agreement, each Party shall cooperate with the other Party to secure any necessary or desirable approval or acceptance of such authorities of such part of this Agreement or such transactions or actions.

17.15 Time of the Essence. With respect to all duties, obligations and rights of the Parties specified by Regulatory Authorities, time shall be of the essence in this Agreement.

17.16 Interpretation. Unless the context of this Agreement otherwise clearly requires:

17.16.1 all defined terms in the singular shall have the same meaning when used in the plural and vice versa;

17.16.2 the terms “hereof,” “herein,” “hereto” and similar words refer to this entire Agreement and not to any particular Section, Attachment or any other subdivision of this Agreement;

17.16.3 references to “Section” or “Appendix” refer to this Agreement, unless specified otherwise;

17.16.4 references to any law, statute, rule, regulation, notification or statutory provision shall be construed as a reference to the same as it applies to this Agreement and may have been, or may from time to time be, amended, modified or re-enacted;

17.16.5 references to “includes,” “including” and similar phrases shall mean “including, without limitation;”

17.16.6 the captions, section numbers and headings in this Agreement are included for convenience of reference only and shall not in any way affect the meaning or interpretation of this Agreement;

17.16.7 "or" may not be mutually exclusive, and can be construed to mean "and" where the context requires there to be a multiple rather than an alternative obligation; and

17.16.8 references to a particular entity include such entity's successors and assigns to the extent not prohibited by this Agreement.

17.17 Joint Effort. Preparation of this Agreement has been a joint effort of the Parties and the resulting document shall not be construed more severely against one of the Parties than against the other and no provision in this Agreement is to be interpreted for or against any Party because that Party or its counsel drafted such provision. Each Party acknowledges that in executing this Agreement it has relied solely on its own judgment, belief and knowledge, and such advice as it may have received from its own counsel, and it has not been influenced by any representation or statement made by the other Party or its counsel not contained in this Agreement.

17.18 Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument, binding upon Company and TranServ, notwithstanding that Company and TranServ may not have executed the same counterpart.

The Parties have caused this Independent Transmission Organization Agreement to be executed by their duly authorized representatives as of the dates shown below.

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY

/s/ Stephanie R. Pryor

Name: Stephanie R. Pryor
Title: Manager Supply Chain
Date: 12/9/2016

TRANSERV INTERNATIONAL, INC.

/s/ Sasan Mokhtari, PhD

Name: Sasan Mokhtari, PhD
Title: President & CEO
Date: 12/8/2016

Appendix A
Louisville Gas and Electric Company/
Kentucky Utilities Company

INDEPENDENT TRANSMISSION ORGANIZATION

SERVICE SPECIFICATION

TABLE OF CONTENTS

1. Overview

This Appendix A is intended to be consistent with the terms and conditions of the

LG&E/KU Open Access Transmission Tariff (OATT), including Attachment P thereto. If there is any conflict between this Appendix A and the OATT, the OATT shall govern. TranServ shall perform its obligations under this Appendix A in accordance with Section 1.3.1 of this Agreement.

The services delegated to TranServ include the administration of the LG&E/KU Open Access Same-time Information System (OASIS), transmission service request evaluation process, Available Transfer Capability (ATC)/ Available Flowgate Capability (AFC) management, study queue administration, study performance, and stakeholder facilitation. TranServ, as the ITO, will administer the OATT granting of service for both short and long-term transmission requests, administer the large generator interconnection request queue, and perform transmission studies. TranServ will facilitate the LG&E/KU long-term transmission planning function and stakeholder processes.

2. Definitions

Company - Louisville Gas and Electric Company/Kentucky Utilities Company (LG&E/KU)

ITO - Independent Transmission Organization

ITO Services - The applicable functions to be performed as specified in the ITO Agreement

RC - Reliability Coordinator

Service Interruption - A Service Interruption is the loss of Service function, under the direct control of TRANSERV with no mutually agreed to work around provided within the Service

Normal Business Hours - TranServ normal business hours are between the hours of 0700 and 1700 CT, Monday-Friday on days other than the holidays listed below:

1. New Year's Day
2. Memorial Day
3. Independence Day
4. Labor Day
5. Thanksgiving
6. Day after Thanksgiving
7. Day before Christmas

8. Christmas Day

3. Roles and Responsibilities for Providing ITO Services

3.1 TranServ

TranServ International, Inc. (TranServ) will provide services to LG&E/KU as the ITO. The services that TranServ will provide include:

3.1.1 Customer Interface

Responsibility for operating and maintaining OASIS website and keeping it up-to-date with Federal Energy Regulatory Commission (FERC) and North American Energy Standards Board (NAESB) posting requirements, including all Order No. 890 posting requirements (such as study performance metrics, Available Transfer Capability (ATC) calculations, etc.). This includes establishing an interface for customers to submit service requests, and oversight and evaluation of ATC values calculated using software procured from Open Access Technology International, Inc. (OATI) and information from the RC. TranServ's responsibilities and duties in administering OASIS will include the following:

- Performing the duties of a Responsible Party as defined in the Commission's OASIS regulations, 18 C.F.R. § 37.5 and FERC Order No. 676.
- Posting information required to be on the Transmission Provider's OASIS under the Commission's OASIS regulations, 18 C.F.R. § 37.6 and FERC Order No. 676.
- Maintaining and retaining information posted on OASIS in accordance with the Commission's regulations, including 18 C.F.R. Parts 37 and 125.
- Establishing and maintaining queues for processing transmission service requests and generator interconnection (GI) requests.
- Participating in the drafting and posting of Business Practices on the OASIS website, including any FERC or NAESB-required Business Practices. Company shall have final review, ownership, and approval for all Business Practices.
- Participating in periodic reviews of, and providing expertise/comments on, the OATT. Company retains final authority over the OATT's content, including retaining the right and responsibility to file changes to the OATT.
- Participating in stakeholder meetings and/or conference calls as required. These stakeholder meetings will include TranServ, Company, Customers (as appropriate) the RC, and other entities as required, to address concerns regarding Company's system,

administration of the OATT, and related issues.

- Responsibility for coordinating with third-party transmission system owners and operators as necessary to support customer service requests. This includes coordinating the provision of any data from Company to the third-party system.
- Management of ATC/AFC Calculation and Posting.
- Implementation of certain aspects of the Congestion Management Process (CMP) established by the Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection LLC (PJM), and TVA.
- Administration of request evaluations for LG&E/KU tariff service.
- Processing of e-Tags as the transmission provider.
- Reviewing software changes requested from OATI, verifying and testing for proper operations before OATI implements those changes.

3.1.2 Transmission Service and Generator Interconnection Requests and Studies

- Receive and process all applications for Point-to-Point, Network Integration Transmission Service (NITS), and for GIs.
- For short-term Point-to-Point Transmission Service requests (i.e., where the request is within the posted ATC horizon), evaluate and approve a request where the posted ATC is sufficient for the requested transaction. If ATC is insufficient, TranServ shall propose conditional service options to the customer in accordance with the OATT, or otherwise deny the service. If the customer accepts conditional service options, TranServ will be responsible for performing biennial reassessments, as provided under the OATT.
- For long-term Point-to-Point Transmission Service requests, NITS, or GI requests:
  - Determine whether a System Impact Study (SIS) is necessary to accommodate the request.
  - Render all study agreements (SIS, Interconnection Feasibility Studies (IFS), Facilities Study (FS), and Feasibility Analysis Studies (FAS)) to customers within the timeframe provided in the OATT.
  - Perform the SIS or FAS in the timeframe provided in the OATT, including clustered SISs when requested by customers and/or Company.

  - Perform the SIS or FAS using Company's planning criteria.
  - For any study that TranServ performs that requires information from Company (e.g., good faith construction estimates that are included in the SIS), request such information from Company no less than ten (10) business days before the expiration of the applicable study period.
  - Complete study reports and post on OASIS within the timeframe required under the OATT.
  - Notify the Company and individual customers of completed study reports, and alert the Company to initiate service agreements, if applicable.
  - Receive customer deposits.
  - Bill customers for SIS, IFS, FS, and FAS as required by the OATT, including provision of an itemized bill for services if requested by a customer.
  - Reimburse Company for any study costs incurred in contributing to the study and render payment to any third-party vendors for work performed.
- Responsible for receiving and processing requests to designate or un-designate Network Resources, as provided under the OATT.
- If a customer requests a modification to its service, or if a customer assigns its transmission service to a third-party who request modification to the service, process those modification requests in accordance with the terms of the OATT.
- Track all study metrics, including data submittals, input validations, modifications, time and costs associated to perform the study.
- Track the performance of all studies and alert Company if a FERC filing requirement or penalty payment has been triggered due to late studies, as described under the OATT.

3.1.3 ATC Calculation

- Calculate ATC as provided for in Attachment C to the OATT. This includes receiving initial AFC values from the RC, calculating final AFC values using the algorithms included in Attachment C, and converting the AFC to ATC using OATI software.
- Post on OASIS the mathematical algorithms used to calculate firm and non-firm AFC. TranServ shall also post the results of the AFC calculations on OASIS.

- Daily review of transmission service requests (TSRs) and eTag action and statistics.
- Daily review of posted AFC/ATC information and investigation into any anomalies.
- Review, observation, and validation of the Total Transfer Capability (TTC) development process.

3.1.4 Interchange and Scheduling

- As the Transmission Service Provider, responsible for the following activities:
  - Confirm that each electronic schedule (e-Tag) has a confirmed transmission service request.
  - Approve the interchange schedules as the transmission service provider.
  - Curtail electronic schedules if requested by the RC or Balancing Authority (BA).
  - Monitor and validate the Net Scheduled Interchange (NSI), as processed by OATI software, to ensure timely creation of the NSI data file with a syntactical quality check on the data set.

3.1.5 Transmission Planning

- TranServ will participate in Company's transmission planning process as outlined in Attachment K to the OATT, including the following activities:
  - Review and approve Company's long-term (generally one year and beyond) plan for the reliability/adequacy of Company's Transmission System.
  - Review and approve Transmission System models (steady state, dynamics, and short circuit).
  - Develop alternatives to Planning Redispatch service.
  - Notify impacted transmission entities of any planned transmission changes that may influence their facilities.
  - Participate with the SPC and associated SPC working groups, as required.
  - Participate in the overall OATT Attachment K process as observer.
  - The Parties agree that the final annual transmission plan and decision of whether/when to construct and expand the system rests with Company.

- Both parties will communicate openly and in a timely manner; each will perform their respective work; and both will continually work together to improve mutual and individual processes in a joint effort to assure work is completed pursuant to Company standards and deadlines.

3.1.6 Compliance

- Establish and adhere to a "culture of compliance" for TranServ Personnel and TranServ Designees consistent with FERC's Policy Statement on Compliance, 125 FERC ¶ 61,058 (2008) as may be supplemented or amended by further FERC orders. TranServ shall take such reasonable steps requested by the Company in furtherance of such a culture of compliance.

- In accordance with *Louisville Gas and Electric Company*, 114 FERC ¶ 61,282 at P 152 (2006), provide FERC with semi-annual reports "detailing concerns expressed by stakeholders and [ITO's] response to those concerns as well as any issues or tariff provisions that hinder [ITO] from performing its required duties" as requested.

- Maintain records and provide reports as required by the Kentucky Public Service Commission (KPSC), OATT, Department of Energy (DOE), FERC, NERC, SERC Reliability Corporation (SERC) or NAESB. Without limiting the foregoing, Company may from time-to-time provide TranServ with specific direction as to records that Company expects to support compliance efforts, and TranServ shall maintain such records as directed.

- Assist Company, as requested by Company, in the preparation of applications, audit materials, filings, reports or responses to any Regulatory Authority. Without limiting the foregoing, this assistance may include from time-to-time preparation for (and participation in, if appropriate) FERC or NERC audits and providing event analysis information for FERC, NERC or SERC. TranServ's support shall be provided in a time frame reasonably requested by Company.

- Monitor FERC, NERC, SERC, and NAESB activities for changes in standards or compliance requirements that may require modification to the ITO Services or other coordination with Company. To the extent possible, TranServ shall notify Company of any proposed or pending modifications prior to their implementation. The Parties shall work together to establish a work plan and timetable for implementation of any such changes. The Parties agree that all changes to ITO Services resulting from legal and regulatory developments as well Company requests, shall be assessed using the change order process detailed in Section 5 of this Appendix A.

3.2 Transmission Planner

TranServ will provide certain services to LG&E/KU, the Transmission Planner (TP). The services include:

3.2.1 Customer Interface

- TranServ will participate in the drafting of Business Practices; including any FERC or NAESB required Business Practices. Company shall have final review, ownership, and approval for all Business Practices.
- TranServ will participate in periodic reviews of, and provide expertise/comments on the OATT. Company retains final authority over the OATT's content, including retaining the right and responsibility to file changes to the OATT.
- Responsible for planning, coordinating and holding regular stakeholder meetings and/or conference calls. These stakeholder meetings will include TranServ, Company, and the RC, and other entities as required, to address concerns regarding Company's system, administration of the OATT, and related issues. This activity includes (as necessary) performing background checks for stakeholders who desire access to Critical Energy Infrastructure Information (CEII), preparing meeting materials, facilitating the meeting, and preparing post-meeting minutes for posting on OASIS.
- Responsible for coordinating with third-party transmission system owners and operators as necessary to support customer service requests. This includes coordinating the provision of any data from Company to the third-party system.

3.3 LG&E/KU

TranServ understands that Company has the following responsibilities in support of the ITO Services under this Appendix A:

3.3.1 Customer Interface

- Contracting for the OATI webSmartOASIS service that meets FERC and NAESB requirements.
- Contracting for the OATI webTrans service used to evaluate and take actions on

transmission service requests and e-Tags.

- Continuation of Agreement with the RC to provide necessary data for AFC/ATC calculation and posting processes.
- Final review, ownership, and approval for all Business Practices.
- Final authority over the OATT's content, including the right and responsibility to file changes to the OATT.
- Cooperate in the coordination with third-party systems as necessary to support customer service requests. This includes coordinating the provision of any data from Company to the third-party system.

3.3.2 Compliance

- From time-to-time provide TranServ with specific direction as to records that Company expects to support compliance efforts, TranServ shall maintain such records as directed in order to provide reports as required by the KPSC, OATT, DOE, FERC, NERC, SERC or NAESB.
- Respond to TranServ notifications of FERC, NERC, SERC, and NAESB activities for changes in standards or compliance requirements that may require modification to the ITO Services or other coordination with Company within requested response timelines. Work together with ITO to establish a work plan and timetable for implementation of any such changes. The Parties agree that all changes to ITO Services resulting from legal and regulatory developments as well Company requests, shall be assessed using the change order process detailed in Section 5 of this Appendix A.

4. Customer Support

TranServ will provide support for Service 24-hours per day and 365-days per year by utilizing a single point of contact support staff. During Normal Business Hours the support staff can be contacted by telephone or by e-mail as outlined in published TranServ's ITO Support Information. After Normal Business Hours support is achieved through telephone only. TranServ will take all reasonable effort to ensure that reported problems or other Customer support related events are responded to within 30-minutes of the event notification when ITO Support Procedures are followed.

4.1 Problem Resolution

Problems or outages are reported to TranServ by following customer support processes. All problems or questions are assigned a severity level by mutual agreement of the parties. Problems which are considered Critical or High in severity should be reported to TranServ at any time. Problems considered Medium or Low severity should be reported by phone during business hours or by e-mail at any time. The severity level classifications are defined as follows:

Critical - Problems or issues that are impacting business immediately or impacting grid reliability and action is required prior to next business day.

High - Problems or issues that affect a key functionality of Service component and there is no work around available but immediate business or grid reliability impact is not present.

Medium - Business processes are impacted, but satisfactory work around is in place to avoid business interruptions.

Low - Customer inquiries or reported problems and issues that create nuisances or inconveniences for the customer. Minimal or no business impact is occurring.

Ticket Resolution		
Action	**TranServ Responsibility**	**Time To Remedy**

Correct a 'Critical' severity Problem or Issue	During normal business hours TranServ will respond to reported Critical severity problems and begin corrective action immediately until either a satisfactory work around is in place or problem is resolved. Outside of normal business hours TranServ will respond to reported Critical severity problems within 30-minutes of notification. Escalation to responsible TranServ senior management will occur in all cases.	TranServ will work continuously until resolution is in place. This may include a temporary work around until a permanent correction can be implemented. **Performance goal is to resolve all Critical severity tickets within 4-hours.**
Correct a 'High' severity Problem or Issue	During normal business hours TranServ will respond to reported High severity problems and begin corrective action to resolve with either a satisfactory work around or problem resolution prior to end of business day. Outside of normal business hours TranServ will respond to reported High severity problems within 30-minutes of notification. Escalation to responsible TranServ senior management will occur in all cases.	TranServ will provide an initial problem analysis update within 8-hours at all times. This may include a recommended temporary work around until a permanent correction can be implemented. **Performance goal is to resolve all High severity tickets within 24-hours.**
Correct a 'Medium' severity Problem or Issue	TranServ will schedule corrective action jointly with Customer. Problems of Medium severity should be reported by telephone during business hours or by e-mail at any time.	TranServ will provide an initial problem analysis update within 3-business days of notification of problem. An appropriate action plan and resolution schedule will be mutually agreed to with the Customer. **Performance goal is to resolve all Medium severity tickets by agreed to commitment date.**
Correct a 'Low' severity Problem or Issue	TranServ will schedule corrective action jointly with Customer. Problems of Low severity should be reported by telephone during business hours or by e-mail at any time.	TranServ will provide an initial problem analysis update within 5-business days. An appropriate action plan and resolution schedule will be mutually agreed to with the Customer. **Performance goal is to resolve all Low severity tickets by agreed to commitment date.**

4.1.1 Tickets - OATI webSupport

To ensure all customers of TranServ receive a high level of customer service all calls or e-mails with questions or reported problems are documented in a Ticket. All TranServ staff members utilize OATI webSupport, an issue reporting and assignment platform allowing tracking and confirmed resolution of all issues reported to TranServ. Upon receiving a communication from a customer, TranServ will open a webSupport Ticket. The Ticket contains customer contact information, data metrics on the type of problem, an identification of the TranServ staff member to whom the Ticket is currently assigned, a detailed description of the problem, and a detailed description of the problem's current status which will eventually include a description of how the issue was resolved. The TranServ staff member provides the Ticket number to the customer for all issues not resolved immediately. If the issue cannot be resolved by the TranServ staff member creating the Ticket, the Ticket is reassigned to another member of the TranServ team. The TranServ staff member who initially created the Ticket is expected to use webSupport's monitoring capability to determine unresolved Tickets, and to reassign or escalate it as necessary at any time to promote prompt resolution within response timing guidelines.

4.1.2 Response Time

TranServ support staff will answer all calls as received during normal business hours and take all reasonable effort to resolve issues at the time of call. For issues and problems that are not immediately resolved, TranServ will follow normal processing for assigned severity level and notify customer once resolution occurs.

Calls to support staff outside of normal business hours will be answered as received and customer will be notified within 30-minutes on planned actions to be taken by TranServ support staff in accordance with normal processing for assigned severity level.

4.1.2.1 Ticket Escalation

Problem tickets that cannot be resolved in accordance with normal processing for assigned severity level will be escalated to appropriate TranServ management. Customers may request immediate ticket escalation to appropriate TranServ management.

4.1.2.2 Customer Satisfaction

Customer satisfaction inquiries are automatically sent to customers upon the closing of a ticket. The results of these surveys result in improved performance by customer support staff or changes in business processes.

5. Service Modifications

From time to time Company may require a modification to an existing Service function. Such modifications may be prompted by changes in regulatory compliance requirements, or by a Company request. Minor modifications that require reasonably minimal resource commitment from TranServ staff will be included within a reasonable time period at no cost to Company. Modifications that may have more significant impact on Service design or will impact TranServ staff resource commitments more than minimally will be discussed with Company and may in some instances require additional payment by Company, or likewise, require a decrease in payment by Company. Each of these change requests will be described in a written Change Order. Each Change Order will be scheduled for implementation upon written agreement with Company as to scope, cost and schedule.

5.1 Minor Changes

Any change to an existing Service function that does not have a significant impact on Service design or require TranServ to staff or contract with additional personnel, if even for a brief period of time, to prepare for and/or meet the requirements of the change (a "Minor Change") will be integrated into Company's Service at no cost to Company. A written Change Order will be negotiated and executed between Company and TranServ prior to implementation of any Minor Change.

5.2 Major Changes

Any change to an existing Service function that has a significant impact on Service design or requires TranServ to staff additional or fewer personnel, if even for a brief period of time, in order to prepare for and/or meet the requirements of the change (a "Major Change") will require a written Change Order which must be negotiated and executed between Company and TranServ prior to implementation of any Major Change.

6. Reliability Coordination

TranServ will be required to coordinate its operations with the LG&E/KU designated RC. The RC is responsible for performing certain reliability related tasks for the LG&E/KU system, including acting as the NERC-registered Reliability Coordinator. The RC's responsibilities are detailed in the Reliability Coordinator Agreement and Attachment P to the LG&E/KU OATT.

AMENDED AND RESTATED RELIABILITY COORDINATOR AGREEMENT

BETWEEN

LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

AND

TENNESSEE VALLEY AUTHORITY

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RELIABILITY COORDINATOR AGREEMENT

This Amended and Restated Reliability Coordinator Agreement (this "Agreement"), including all appendices, exhibits, and attachments, appended hereto, is entered into this 25th day of August, 2014 ("Execution Date"), between Louisville Gas and Electric Company and Kentucky Utilities Company, corporations organized pursuant to the laws of the State of Kentucky (collectively, "LG&E/KU"), and the Tennessee Valley Authority, a federal government corporation ("TVA" and, in its capacity as reliability coordinator pursuant to this Agreement, the "Reliability Coordinator") created by and existing under and by virtue of the Tennessee Valley Authority Act of 1933, as amended, 16 U.S.C. §§ 831 *et seq.* (the "TVA Act"). LG&E/KU and the Reliability Coordinator may sometimes be referred to herein individually as a "Party" and collectively as the "Parties."

RECITALS

WHEREAS, LG&E/KU owns, among other things, an integrated electric transmission system ("Transmission System"), over which they currently provide open access transmission service to customers in the LG&E/KU Balancing Authority Area (as defined in Section 1.5 of LG&E/KU's Open Access Transmission Tariff, as on file with the Federal Energy Regulatory Commission ("FERC") and as may be changed from time to time (the "OATT"));

WHEREAS, LG&E/KU desires to have the Reliability Coordinator perform certain key reliability functions under the OATT, including: (i) reliability coordination (as defined in the relevant North American Electric Reliability Council ("NERC") Standards); (ii) transmission planning and regional coordination; (iii) approving LG&E/KU's maintenance schedules; (iv) identifying upgrades required to maintain reliability; (v) non-binding recommendations relating to economic transmission system upgrades; and (vi) administration of any seams agreements;

WHEREAS, LG&E/KU desires to have the Reliability Coordinator perform all functions identified for reliability coordinators in NERC's Standards;

WHEREAS, LG&E/KU will retain all remaining NERC obligations, including obligations associated with its status as a Control Area (including operations as a Balancing Authority and Transmission Operator as defined by NERC) and its obligations to ensure the provision of transmission services under the OATT, and will take action necessary to protect reliability of the Transmission System, including circumstances where such action is necessary to protect, prevent or manage emergency situations;

WHEREAS, the Reliability Coordinator is: (i) a federal government corporation charged with providing electric power, flood control, navigational control, agricultural and industrial development, and other services to a region including Tennessee and parts of six contiguous states; and (ii) recognized by NERC as a reliability coordinator;

WHEREAS, the Reliability Coordinator is independent from LG&E/KU, possesses the necessary competence and experience to perform the functions provided for hereunder and is willing to perform such functions under the terms and conditions agreed upon by the Parties as set forth in this Agreement;

WHEREAS, as part of LG&E/KU's goal to maintain the requisite level of independence in the operation of its Transmission System to prevent any exercise of transmission market power, LG&E/KU has entered into an Independent Transmission Organization Agreement (the "Independent Transmission Organization Agreement") with TranServ International, Inc. (the "Independent Transmission Organization" or "ITO"), pursuant to which the Independent Transmission Organization provides to LG&E/KU certain key transmission-related functions under the OATT;

WHEREAS, LG&E/KU seeks to ensure the full participation of the LG&E/KU Transmission System in the arrangements and protocols included in Congestion Management Process ("CMP"), which is Exhibit 1 hereto;

WHEREAS, through the Joint Reliability Coordination Agreement ("JRCA") between TVA and PJM Interconnection, L.L.C. ("PJM"), TVA and PJM participate in CMP;

WHEREAS, the Midcontinent Independent Operator, Inc. ("MISO"), through its Joint Operating Agreement with PJM, also participates in the CMP;

WHEREAS, by virtue of the reciprocity requirements found in Section 6.2 of the CMP, TVA will coordinate with MISO in order to manage regional coordination issues applicable under the CMP between the LG&E/KU system and MISO;

WHEREAS, TVA and LG&E/KU may choose to participate in similar reliability coordination agreements with other neighboring reliability coordination areas.

NOW THEREFORE, in consideration of the mutual promises contained herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties hereby agree as follows:

Section 1 - Designation; Scope of Functions; Standards of Performance; Reliability Coordination Advisory Committee.

1.1 Designation. LG&E/KU appoints TVA to act as LG&E/KU's designated Reliability Coordinator pursuant to and in accordance with the terms and conditions of this Agreement. The Reliability Coordinator shall have no responsibility to LG&E/KU, except as specifically set forth in this Agreement.

1.2 Scope of Functions. The Reliability Coordinator shall perform the functions assigned to it and described in Attachment A and Attachment B (the "Functions") seven days a week, twenty-four hours a day, for the duration of the Term in accordance with the terms and conditions of this Agreement. In accordance with its obligations under this Section 1.2, the Reliability Coordinator is authorized to, and shall, direct and coordinate timely and appropriate actions by LG&E/KU, including curtailing transmission service or energy schedules, redispatching generation, and shedding load, in each case, in order to avoid adverse effects on interregional bulk power reliability.

1.2.1 Relationship Between this Agreement and Attachment L to LG&E/KU's OATT. The Parties recognize that the relationship between LG&E/KU and the Reliability Coordinator and the Functions to be performed by the Reliability Coordinator must be reflected in LG&E/KU's OATT. The Reliability Coordinator relationship and the Functions assigned to the Reliability Coordinator under Attachment A and Attachment B to this Agreement shall be reflected in Attachment L to LG&E/KU's OATT. To the extent that there is a conflict between Attachment A and/or Attachment B to this Agreement and Attachment L to LG&E/KU's OATT, Attachment L to LG&E/KU's OATT shall govern. Any changes proposed by LG&E/KU to FERC in Attachment L in LG&E/KU's OATT, pursuant to Section 5.3 of Attachment L in LG&E/KU's OATT, regarding the Functions or any other provisions that concern the Reliability Coordinator shall reflect the mutual agreement of the Parties. Notwithstanding this Section 1.2.1, nothing in this Agreement or Attachment L to LG&E/KU's OATT shall grant FERC any additional jurisdiction over TVA.

1.3 <u>Reliability Coordinator Procedures</u>. The Reliability Coordinator shall develop the procedures and guidelines by which it will perform the Functions (the “<u>Reliability Coordinator Procedures</u>”) in coordination with the RCAC (as defined in <u>Section 1.10</u>) and applicable regional reliability councils. The Reliability Coordinator Procedures shall be documented in a NERC-approved reliability plan for the TVA Reliability Coordination Area or in TVA Standard Procedures and Policies. The Reliability Coordinator shall provide LG&E/KU advance written notice of any amendment or change to the Reliability Coordinator Procedures. For purposes of this Agreement, the term “TVA Standard Procedures and Policies” shall mean such procedures and policies related to TVA’s operations as may be promulgated and published by TVA pursuant to its legal authorities and obligations.

1.4 <u>Threat to Reliability</u>. If the Reliability Coordinator determines that an actual or potential threat to transmission system reliability exists, and that such threat may impair the reliability of a transmission system, then the Reliability Coordinator shall direct that LG&E/KU take whatever actions are necessary, consistent with Good Utility Practice (as defined below) and in accordance with the applicable reliability criteria, policies, standards, rules, regulations and other requirements of NERC (collectively, the “<u>NERC Standards</u>”) and any applicable regional reliability councils or their successors (collectively, “<u>Regional Reliability Council Standards</u>”), to avoid or mitigate the effects of the threat to transmission system reliability. For purposes of this Agreement, “<u>Good Utility Practice</u>” shall mean any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts that, in a person’s exercise of reasonable judgment in light of the facts as known to that person at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to include the range of acceptable practices, methods, or acts generally accepted in the region.

1.5 <u>Reliability Coordinator Directives</u>. Except as provided in the immediately succeeding sentence, LG&E/KU shall implement any directive given by the Reliability Coordinator pursuant to <u>Sections 1.2</u> or <u>1.4</u>. LG&E/KU shall not be obligated to implement any directive which LG&E/KU determines will violate any state or federal law or the terms of any governmental approval applicable to LG&E/KU. LG&E/KU may review any directive given by the Reliability Coordinator pursuant to <u>Sections 1.2</u> or <u>1.4</u>, to determine if it is, in LG&E/KU’s judgment, in accordance with the requirements of <u>Section 1.8</u>. If LG&E/KU determines that any directive is not in accordance with the requirements of <u>Section 1.8</u>, then it shall immediately so notify the Reliability Coordinator; <u>provided</u>, <u>however</u>, that, except as provided in the second sentence in this <u>Section 1.5</u>, LG&E/KU shall continue to implement the directive until the Reliability Coordinator notifies LG&E/KU otherwise. LG&E/KU's notice to the Reliability Coordinator shall include: (a) information outlining the basis for LG&E/KU's determination that (i) the directive is not in accordance with the requirements of Section 1.8 and, if applicable, (ii) that implementation of the directive will violate one or more state or federal laws or the terms of any governmental approvals applicable to LG&E/KU; and (b) the alternative action that LG&E/KU would prefer to take to alleviate the problem addressed by the Reliability Coordinator's directive. After prompt consideration of such information, the Reliability Coordinator shall issue a directive to LG&E/KU in accordance with its obligations under this Agreement and LG&E/KU will, subject to the second sentence in this Section 1.5, act in accordance with such directive.

1.6 Coordination with Independent Transmission Organization. In conjunction with its performance of the Functions, the Reliability Coordinator shall coordinate and cooperate with the Independent Transmission Organization and provide, subject to the terms and conditions of this Agreement, including the Reliability Coordinator's obligations with respect to Confidential Information in Section 10, any information that the Independent Transmission Organization may reasonably request in order to carry out its functions under the Independent Transmission Organization Agreement.

1.7 Expansion. Nothing in this Agreement is intended to prevent TVA from (a) coordinating, or cooperating in, interregional activities to relieve problems experienced by other transmission systems or (b) entering into other agreements with one or more third party transmission providers or operators to perform functions for such transmission providers or operators that are the same or similar to the Functions performed hereunder; provided, however, that it does not breach any of its obligations under this Agreement (including its obligations with respect to Confidential Information in Section 10) by entering into or performing any of its obligations under such other agreements; provided, further, that (i) any such other agreements shall provide for LG&E/KU to be reimbursed in an equitable manner for any capital expenditures made pursuant to this Agreement as well as for LG&E/KU's ongoing operations and maintenance expenditures to the extent such capital expenditures and operations and maintenance expenditures are used by the Reliability Coordinator in performing functions under such other agreements, (ii) LG&E/KU agrees to reimburse any such third party transmission providers or operators in an equitable manner for any capital expenditures made by such third parties as well as for such third parties' ongoing operations and maintenance expenditures to the extent such capital expenditures and operations and maintenance expenditures are used by the Reliability Coordinator in performing functions under this Agreement, and (iii) to the extent applicable, the Reliability Coordinator shall revise the compensation provided for in Section 3.1 in accordance with the terms therein.

1.8 Reliability Coordinator's Standard of Performance. The Reliability Coordinator shall perform its obligations under this Agreement in accordance with: (a) Good Utility Practice; (b) the NERC Standards and Regional Reliability Council Standards; (c) LG&E/KU's specific reliability requirements and operating guidelines (to the extent these are not inconsistent with other requirements specified in this Section 1.8); (d) TVA Standard Procedures and Policies; and, (e) all state and federal laws, including the TVA Act, and the terms of governmental approvals applicable to one or both of the Parties. In performing its responsibilities under this Agreement, the Reliability Coordinator shall not discriminate against similarly situated persons.

1.9 LG&E/KU's Standard of Performance. LG&E/KU shall perform its obligations under this Agreement in accordance with: (a) Good Utility Practice; (b) the NERC Standards and

Regional Reliability Council Standards; (c) any other LG&E/KU-specific reliability requirements and operating guidelines (to the extent these are not inconsistent with other requirements specified in this Section 1.9); and (d) all state and federal laws and the terms of governmental approvals applicable to LG&E/KU.

1.10 Reliability Coordination Advisory Committee.

1.10.1 Each Party shall designate one representative to serve on a Reliability Coordination Advisory Committee ("RCAC"), which shall be composed of representatives of each Party and representatives from each entity that has executed a similar reliability coordination agreement designating TVA as its reliability coordinator. Each Party may also designate one alternate to act in the absence of its representative on the RCAC. Written notice of each representative and alternate appointment shall be provided to each RCAC entity, and each Party may change its representatives upon written notice to the other RCAC entities.

1.10.2 The RCAC shall assist the Reliability Coordinator in the development of the initial Reliability Coordinator Procedures and the modification of existing Reliability Coordinator Procedures. In connection with these activities, the Reliability Coordinator may provide the other RCAC members with access to necessary data and documents maintained by the Reliability Coordinator, provided that each such RCAC member has signed the NERC Data Confidentiality Agreement and that all Confidential Information is treated as transmission operations and transmission system information pursuant to the NERC Data Confidentiality Agreement.

The RCAC shall meet at least once per Contract Year (as defined below). For purposes of this Agreement, a "Contract Year" shall consist of a twelve (12) month period. "Contract Year 1" shall begin on the Effective Date. Contract Years 2, 3, and 4 shall consist of the next three successive 12-month periods after Contract Year 1.

Section 2 - Independence.

2.1 Key Personnel. All Functions shall be performed by employees of the Reliability Coordinator identified in Attachment C (the "Key Personnel"). The Reliability Coordinator may from time to time change the names of the employees identified as Key Personnel by notice to LG&E/KU in accordance with Section 15.1. No Key Personnel shall also be employed by LG&E/KU or any of its Affiliates (as defined in 18 C.F.R. § 35.34(b)(3) of FERC's regulations). The Reliability Coordinator and the Key Personnel shall be, and shall remain throughout the Term, Independent (as defined below) of LG&E/KU, its Affiliates and the Independent Transmission Organization. For purposes of this Agreement: "Independent" shall mean that the Reliability Coordinator and the Key Personnel are not subject to the control of LG&E/KU, its Affiliates or the Independent Transmission Organization, and have full decision making authority to perform all Functions in accordance with the provisions of this Agreement. Any Key Personnel owning securities in LG&E/KU, its Affiliates or the Independent Transmission Organization shall divest such securities within six (6) months of first being assigned to perform such Functions, provided that nothing in this Section 2.1 shall be interpreted or construed to preclude any such Key Personnel from indirectly owning securities issued by LG&E/KU, its Affiliates or the Independent Transmission Organization through a mutual fund or similar arrangement (other than a fund or arrangement specifically targeted toward the electric industry or the electric utility industry or any segment thereof) under which the Key Personnel does not control the purchase or sale of such securities. Participation by any Key Personnel in a pension plan of LG&E/KU, its Affiliates or the Independent Transmission Organization shall not be deemed to be a direct financial interest if the plan is a defined-benefit plan that does not involve the Key Personnel's ownership of the securities. For the avoidance of doubt, LG&E/KU shall not have an approval or consent right with respect to the selection of any Key Personnel.

2.2 Standards of Conduct Treatment. All Key Personnel shall be treated, for purposes of FERC's Standards of Conduct, as transmission employees. All restrictions relating to information sharing and other relationships between merchant employees and transmission employees shall apply to the Key Personnel.

Section 3 - Compensation, Billing and Payment.

3.1 Compensation. LG&E/KU shall pay to the Reliability Coordinator as compensation for the performance of the Functions under this Agreement as follows:

Subsequent Term Beginning	**Amount**
September 1, 2014	**$2,375,000**
September 1, 2015	**$2,422,500**
September 1, 2016	**$2,470,950**
September 1, 2017	**$2,520,369**
September 1, 2018	**$2,570,776**

The Reliability Coordinator agrees that if at any time during the Term it expands its Reliability Coordination Area by providing similar services to additional Transmission Operators, the Reliability Coordinator will review and revise, as appropriate, the above compensation rate. Such revised compensation shall enable the Reliability Coordinator to recover its incremental costs associated with providing the specific service by allocating the costs among those subscribing to the service in an equitable manner (*e.g.*, costs may be allocated using a load ratio share methodology (a participant's annual non-coincident peak load as a percentage of the total annual non-coincident peak load for those participating in the service)). Costs will be determined by the Reliability Coordinator based on its total cost of providing the service(s) as documented in the Reliability Coordinator's financial systems.

Compensation for Subsequent Terms (as defined in Section 4.2 herein) beyond those delineated above shall be based on the compensation in previous Contract Years and/or the methodology outlined above in this Section 3.1 and shall be negotiated by the Parties in good faith. Such negotiations shall begin not later than six months prior to, and shall be concluded no later than three months prior to, the beginning of the Subsequent Term.

Notwithstanding any provision to the contrary contained in this Agreement, if a Dispute should occur between the Parties with respect to the amount of compensation to be paid by LG&E/KU to the Reliability Coordinator (i) pursuant to this Sections 3.1 or (ii) in respect of additional services (other than the Functions) requested by LG&E/KU that the Reliability Coordinator elects, in its sole discretion, to provide, then, in each case, LG&E/KU shall file notice thereof with FERC. The Parties acknowledge that any FERC order issued with respect to such a dispute is only binding on LG&E/KU, not TVA.

3.2 Compensation After Termination. If LG&E/KU terminates this Agreement before the end of a Contract Year, then the Reliability Coordinator shall not be obligated to refund any amounts paid by LG&E/KU to the Reliability Coordinator as compensation for services provided by the Reliability Coordinator under this Agreement. If, however, the Reliability Coordinator terminates this Agreement before the end of a Contract Year or LG&E/KU and the Reliability Coordinator mutually agree to terminate this Agreement, then the Reliability Coordinator shall be obligated to refund to LG&E/KU an amount equal to the product of (a) any amounts paid by LG&E/KU to the Reliability Coordinator as compensation for services provided by the Reliability Coordinator under this Agreement during the Contract Year in which this Agreement is terminated and (b) the number of whole or partial months remaining in the Contract Year divided by twelve (12).

3.3 Reimbursement of Additional Costs. In addition to the compensation provided for in Section 3.1, LG&E/KU shall reimburse the Reliability Coordinator for (a) any additional costs incurred by the Reliability Coordinator at the request or direction of LG&E/KU or (b) any reasonable additional one-time costs necessarily incurred by Reliability Coordinator related to its activities under this Agreement that are not associated with services provided for in Section 3.1. Any costs under item (b) above shall be appropriately allocated by TVA among the Parties and those other entities that have executed similar reliability coordination agreements designating TVA as their reliability coordinator.

3.4 Payments. All payments by LG&E/KU to the Reliability Coordinator shall be made by the FedWire transfer method to the Reliability Coordinator's account at the U.S. Treasury in accordance with the wire instructions indicated below, and all such payments shall be deemed received as of the date the electronic funds transfer to the Reliability Coordinator's account is deemed effective.

Bank Name: TREAS NYC (official abbreviation)

Bank Address: New York Federal Reserve Bank, New York City
33 Liberty Street
New York, New York 10045

ABA Number: 021030004

Account No: 0004912

Beneficiary: Tennessee Valley Authority

Taxpayer ID: 62-0474417

OBI: Provide your organization name and invoice number or explanation of payment.

The Reliability Coordinator shall provide LG&E/KU with one or more contact persons for payment purposes and shall update such list of contact persons as necessary.

Section 4 - Effective Date; Term; Termination; Termination Fees; Transition Assistance Services.

4.1 Effective Date. The Parties acknowledge and agree that the effective date of this Agreement (the "Effective Date") shall be September 1, 2014 or such other date as permitted by

FERC

4.2 Term. This Agreement shall commence on Effective Date (as provided for in Section 4.1), and shall automatically continue for successive one-year terms (each, a "Subsequent Term") unless and until terminated pursuant to the termination provisions hereof. All Subsequent Terms, together with the Transition Assistance Period, if any, shall collectively be referred to as the "Term."

4.3 Mutually-Agreed Termination. This Agreement may be terminated by mutual agreement of the Parties at any time during the Term.

4.4 Termination at End of Term. Either Party may terminate this Agreement at the end of any Subsequent Term upon one (1) year's prior written notice to the other Party.

4.5 Termination for Cause.

4.5.1 Termination by Either Party. Either Party may terminate this Agreement effective immediately upon thirty (30) days' prior written notice thereof to the other Party if:

(a) Material Failure or Default. The other Party fails to comply with, observe or perform, or defaults, in any material respect, in the performance of the terms and conditions of this Agreement, and such failure or default remains uncured for thirty (30) days after notice thereof, provided that such failure or default is susceptible to cure and the other Party is exercising reasonable diligence to cure such failure or default;

(b) Pattern of Failure. It determines, in its sole discretion, that there has been a pattern of failure by the other Party to comply with the standards of performance required under this Agreement;

(c) Gross Negligence, Willful Misconduct or Fraud. The other Party commits gross negligence, willful misconduct or fraud in the performance of its obligations under this Agreement;

(d) Material Misrepresentation. Any representation made by the other Party hereunder shall be false or incorrect in any material respect when made and such misrepresentation is not cured within thirty (30) days of such discovery or is incapable of cure;

(e) Bankruptcy. The other Party: (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it; (ii) makes an assignment or any general arrangement for the benefit of creditors; (iii) otherwise becomes bankrupt or insolvent (however evidenced); (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets; or (v) is generally unable to pay its debts as they fall due;

(f) Dissolution. The other Party dissolves or is dissolved or its legal existence is otherwise terminated;

(g) Failure to Negotiate Amendment. The Parties are unsuccessful in negotiating an amendment or amendments to this Agreement pursuant to Section 17.6;

(h) Regulatory Changes/Modifications. FERC, in accepting this Agreement for filing, makes any material changes, modifications, additions, or deletions to this Agreement; or

(i) Extended Force Majeure. A Party is excused because of Force Majeure (as defined in Section 11 herein) for more than thirty (30) days from performing any of its material obligations under this Agreement.

4.5.2 Termination by LG&E/KU. LG&E/KU may terminate this Agreement effective immediately upon thirty (30) days' prior written notice thereof to the Reliability Coordinator if:

(a) the Reliability Coordinator loses its NERC certification once obtained; or

(b) FERC issues an order determining that TVA should no longer serve as LG&E/KU's Reliability Coordinator pursuant to this Agreement.

4.5.3 Termination by the Reliability Coordinator. The Reliability Coordinator may terminate this Agreement effective immediately upon thirty (30) days' prior written notice thereof to LG&E/KU if:

(a) LG&E/KU determines to cease being a Balancing Authority and/or Transmission Operator, provided that LG&E/KU shall provide the Reliability Coordinator as much advance written notice of such determination as is practicable to allow the Reliability Coordinator to terminate this Agreement on or prior to the time LG&E/KU ceases to be a Balancing Authority or Transmission Operator;

(b) FERC or any other person or entity takes any action to subject the Reliability Coordinator to FERC's plenary jurisdiction under the Federal Power Act ("FPA"); or

(c) Effective Date has not occurred within eighteen (18) months of the Execution Date.

4.6 Return of Materials. Upon any termination of this Agreement or the conclusion of any Transition Assistance Period pursuant to Section 4.8.1, whichever is later, the Reliability Coordinator shall timely and orderly turn over to LG&E/KU all materials that were prepared or developed prior thereto pursuant to this Agreement, and return or destroy, at the option of LG&E/KU, all Data and other information supplied by LG&E/KU to the Reliability Coordinator or created by the Reliability Coordinator on behalf of LG&E/KU.

4.7 Survival. All provisions of this Agreement which are by their nature or terms intended to survive the termination of this Agreement, including the obligations set forth in Sections 7 and 10, shall survive termination of this Agreement.

4.8 Transition Assistance Services.

4.8.1 Transition Assistance Period. Commencing on the date this Agreement is terminated and continuing for up to one (1) year thereafter (the "Transition Assistance Period"), the Reliability Coordinator shall (a) provide the Functions (and any replacements thereof or substitutions therefor), to the extent LG&E/KU requests such Functions to be performed during the Transition Assistance Period, and (b) cooperate with LG&E/KU in the transfer of the Functions (collectively, the "Transition Assistance Services"). During the Transition Assistance Period, the Parties shall use good faith efforts to ensure a smooth transition.

4.8.2 Transition Assistance Services. The Reliability Coordinator shall, upon LG&E/KU's request, provide the Transition Assistance Services during the Transition Assistance Period at the Reliability Coordinator's actual cost for such services. The quality and level of performance of the Functions by the Reliability Coordinator during the Transition Assistance Period shall not be degraded. After the expiration of the Transition Assistance Period, the Reliability Coordinator shall answer questions from LG&E/KU regarding the Functions on an "as needed" basis at the Reliability Coordinator's then-standard billing rates.

4.8.3 Key Personnel. During the Transition Assistance Period, the Reliability Coordinator shall not terminate, reassign or otherwise remove any Key Personnel without providing LG&E/KU thirty (30) days' prior notice of such termination, reassignment or removal unless such employee (a) voluntarily resigns from the Reliability Coordinator, (b) is dismissed by the Reliability Coordinator for cause, or (c) dies or is unable to work due to his or her disability.

4.9 Change in Reliability Entity. This Agreement is based on the existence of NERC and the applicability of the NERC Standards. If NERC ceases to exist in its current form or is replaced with an entity with authority over a Party's transmission system, the Parties shall promptly meet to determine whether to revise this Agreement to reflect the new reliability entity, if any, and the Parties' obligations in light of the new reliability entity or to terminate this Agreement in accordance with Section 4.2.

4.10 Prior Obligations and Liabilities Unaffected by Termination. Termination of this Agreement shall not relieve the Parties of any of their respective cost obligations or other obligations and liabilities related to this Agreement that were incurred prior to the effective date of termination of this Agreement.

Section 5 - Data Management.

5.1 Supply of Data. During the Term, LG&E/KU shall supply to the Reliability Coordinator, and/or grant the Reliability Coordinator access to all Data that the Reliability Coordinator reasonably requires to perform the Functions. The Parties shall agree upon the initial format and manner in which such Data shall be provided. For purposes of this Agreement, "Data" means all information, text, drawings, diagrams, images or sounds which are embodied in any electronic or tangible medium and which (a) are supplied or in respect of which access is granted to the Reliability Coordinator by LG&E/KU under this Agreement, which shall be LG&E/KU's Data, (b) are prepared, stored or transmitted by the Reliability Coordinator solely on behalf of LG&E/KU, which shall be LG&E/KU's Data; or (c) are compiled by the Reliability Coordinator by aggregating Data owned by LG&E/KU and Data owned by third parties, which shall be Reliability Coordinator's Data.

5.2 Property of Each Party. Each Party acknowledges that the other Party's Data and the other Party's software, base data models and operating procedures for software or base data models ("Processes") are the property of such other Party and agrees that it will do nothing inconsistent with such ownership, including preserving all intellectual property and/or proprietary rights in such other Party's Data and Processes as provided in Section 6.

5.3 Data Integrity. Each Party shall reasonably assist the other Party in establishing measures to preserve the integrity and prevent any corruption or loss of Data, and the Parties shall reasonably assist each other in the recovery of any corrupted or lost Data. Each Party shall retain and preserve any of the other Party's Data that are supplied to it during the Term, and shall exercise commercially reasonable efforts to preserve the integrity of the other Party's Data that are supplied to it during the Term, in order to prevent any corruption or loss of the other Party's Data.

5.4 Confidentiality. Each Party's Data shall be treated as Confidential Information in accordance with the provisions of Section 10.

Section 6 - Intellectual Property.

6.1 Pre-Existing Intellectual Property. Each Party shall own (and continue to own) all trade secrets, Processes and designs and other intellectual property that it owned prior to entering this Agreement, including any enhancements thereto ("Pre-Existing Intellectual Property"). Each Party acknowledges the ownership of the other Party's Pre-Existing Intellectual Property and agrees that it will do nothing inconsistent with such ownership. Each Party agrees that nothing in this Agreement shall give it any right, title or interest in the other Party's Pre-Existing Intellectual Property, other than the rights set forth in this Agreement. The Reliability Coordinator's Pre-Existing Intellectual Property shall include the Reliability Coordinator Retained Rights set forth in Section 6.3. LG&E/KU's Pre-Existing Intellectual Property shall include LG&E/KU Retained Rights set forth in Section 6.4.

6.1.1 Exclusion. Nothing in this Agreement shall prevent either Party from using general techniques, ideas, concepts and know-how gained by its employees during the performance of its obligations under this Agreement in the furtherance of its normal business, to the extent that it does not result in disclosure of the other Party's Data or any data generated from the other Party's Data or other Confidential Information or an infringement by LG&E/KU or the Reliability Coordinator of any intellectual property right. For the avoidance of doubt, the use by a Party of such general techniques, ideas, concepts and know-how gained by its employees during the performance of its obligations under this Agreement shall not be deemed to be an infringement of the other Party's intellectual property rights so long as such matters are retained in the unaided memories of such employees and any Confidential Information is treated in accordance with the provisions of Section 10.

6.2 Jointly-Owned Intellectual Property. Except for the Data described in Section 5.1, all deliverables, whether software or otherwise, to the extent originated and prepared by the Reliability Coordinator exclusively in connection with the performance of its obligations under this Agreement shall be, upon payment of all amounts that may be due from LG&E/KU to the Reliability Coordinator, jointly owned by LG&E/KU and Reliability Coordinator ("Jointly-Owned Intellectual Property"). Each Party shall have the right to use the Jointly-Owned Intellectual Property without any right or duty or accounting to the other Party, except as provided in this Section 6.2. Upon the Reliability Coordinator using, transferring or licensing Jointly-Owned Intellectual Property for or to a third party, the Reliability Coordinator shall reimburse LG&E/KU in an equitable manner as determined by the Parties in good faith for the actual amounts paid by LG&E/KU to the Reliability Coordinator that relate to such Jointly-Owned Intellectual Property. Except as stated in the foregoing sentence, the Reliability Coordinator shall have no other obligation to account to LG&E/KU for any such use, transfer, license, disclosure, copying, modifying or enhancing of the Jointly-Owned Intellectual Property. Notwithstanding anything herein to the contrary, LG&E/KU may use the Jointly-Owned Intellectual Property for its internal business purposes, including licensing or transferring its interests therein to a third party for purposes of operating or performing functions in connection with LG&E/KU's transmission business.

6.3 Reliability Coordinator Retained Rights. The Reliability Coordinator shall retain all right, title and interest in its proprietary know-how, concepts, techniques, processes, materials and information that were or are developed entirely independently of this Agreement ("Reliability Coordinator Retained Rights"), whether or not such Reliability Coordinator Retained Rights are embodied in a deliverable, whether software or otherwise originated and prepared by the Reliability Coordinator in connection with the performance of its obligations under this Agreement. With respect to the Reliability Coordinator Retained Rights embodied in any deliverable, whether software or otherwise originated and prepared by the Reliability Coordinator in connection with the performance of its obligations under this Agreement, LG&E/KU is hereby granted a nonexclusive, perpetual, worldwide, royalty-free, fully paid-up license under such Reliability Coordinator Retained Rights to use such deliverable for LG&E/KU's internal business purposes only, including licensing or transferring its interests therein to an Affiliate of LG&E/KU or a third party for purposes of operating or performing functions in connection with LG&E/KU's transmission business.

6.4 LG&E/KU Retained Rights. LG&E/KU shall retain all right, title and interest in its proprietary know-how, concepts, techniques, processes, materials and information that were or are developed entirely independently of this Agreement ("LG&E/KU Retained Rights"), whether or not such LG&E/KU Retained Rights are embodied in a deliverable, whether software or otherwise originated and prepared by LG&E/KU in connection with the performance of its obligations under this Agreement. With respect to LG&E/KU Retained Rights embodied in any software or otherwise originated and prepared by LG&E/KU in connection with the performance of its obligations under this Agreement, the Reliability Coordinator is hereby granted a nonexclusive, worldwide, royalty-free, fully paid-up license under such LG&E/KU Retained Rights to use such deliverable for the Reliability Coordinator's performance of its obligations under this Agreement only; provided that LG&E/KU shall not be liable in any way for the use of or reliance on such Reliability Coordinator Retained Rights by the Reliability Coordinator's Affiliate or third party for any purpose whatsoever.

6.5 Reliability Coordinator Non-Infringement; Indemnification. The Reliability Coordinator warrants to LG&E/KU that all Reliability Coordinator's Data and Processes, Reliability Coordinator Pre-Existing Intellectual Property, Reliability Coordinator Retained Rights, and deliverables prepared, produced or first developed by the Reliability Coordinator in connection with the performance of its obligations under this Agreement shall not infringe on any third party patent, copyright, trade secret or other third party proprietary rights. The Reliability Coordinator shall defend, hold harmless and indemnify LG&E/KU and its Affiliates and their respective employees, officers, directors, principals, owners, partners, shareholders, agents, representatives, consultants, and subcontractors (collectively, "LG&E/KU Representatives") from and against all claims, lawsuits, penalties, awards, judgments, court arbitration costs, attorneys' fees, and other reasonable out-of-pocket costs incurred in connection with such claims or lawsuits based upon the actual or alleged infringement of any of the foregoing rights; provided that LG&E/KU gives prompt written notice of any such claim or action to the Reliability Coordinator, permits the Reliability Coordinator to control the defense of any such claim or action with counsel of its choice, and cooperates with the Reliability Coordinator in the defense thereof; and further provided that such claim or action is not based on any alteration, modification or combination of the deliverable with any item, information or process not provided by the Reliability Coordinator, where there would be no infringement in the absence of such alteration, modification or combination. If any infringement action results in a final injunction against LG&E/KU or the LG&E/KU Representatives with respect to Reliability Coordinator's Data and Processes, Reliability Coordinator Pre-Existing Intellectual Property, Reliability Coordinator Retained Rights or deliverables prepared, produced or first developed by the Reliability Coordinator in connection with the performance of its obligations under this Agreement or in the event the use of such matters or any part thereof, is, in such lawsuit, held to constitute infringement, the Reliability Coordinator agrees that it shall, at its option and sole expense, either (a) procure for LG&E/KU or the LG&E/KU Representatives the right to continue using the infringing matter, or (b) replace the infringing matter with non-infringing items of equivalent functionality or modify the same so that it becomes non-infringing and retains its full functionality. If the Reliability Coordinator is unable to accomplish (a) or (b) above, the Reliability Coordinator shall reimburse LG&E/KU for all costs and fees paid by LG&E/KU to the Reliability Coordinator for the infringing matter. The above constitutes the Reliability Coordinator's complete liability for claims of infringement relating to any the Reliability Coordinator's Data and Processes, Reliability Coordinator Pre-Existing Intellectual Property, Reliability Coordinator Retained Rights, and deliverables prepared, produced or first developed by the Reliability Coordinator in connection with the performance of its obligations under this Agreement.

6.6 LG&E/KU Non-Infringement; Indemnification. LG&E/KU warrants to the Reliability Coordinator that, to its knowledge, all LG&E/KU's Data (except for Data created by the Reliability Coordinator on behalf of LG&E/KU) and Processes, LG&E/KU Pre-Existing Intellectual Property, and LG&E/KU Retained Rights shall not infringe on any third party patent, copyright, trade secret or other third party proprietary rights. LG&E/KU shall defend, hold harmless and indemnify the Reliability Coordinator and its Affiliates and their respective employees, officers, directors, principals, owners, partners, shareholders, agents, representatives, consultants, and subcontractors against all claims, lawsuits, penalties, awards, judgments, court costs, and arbitration costs, attorneys' fees, and other reasonable out-of-pocket costs incurred in connection with such claims or lawsuits based upon the actual or alleged infringement of any of the foregoing rights; provided that the Reliability Coordinator gives prompt written notice of any such claim or action to LG&E/KU, permits LG&E/KU to control the defense of any such claim or action with counsel of its choice, and cooperates with LG&E/KU in the defense thereof; and further provided that such claim or action is not based on any alteration, modification or combination of the deliverable with any item, information or process not provided by LG&E/KU to the Reliability Coordinator, where there would be no infringement in the absence of such alteration, modification or combination. The above constitutes LG&E/KU's complete liability for claims of infringement relating to any of the LG&E/KU's Data and Processes, LG&E/KU Pre-Existing Intellectual Property, and LG&E/KU Retained Rights.

Section 7 - Indemnification.

7.1 Indemnification by the Parties. Each Party ("Indemnifying Party") shall indemnify, release, defend, reimburse and hold harmless the other Party and its Affiliates, and their respective directors, officers, employees, principals, representatives and agents (collectively, the "Indemnified Parties") from and against any and all claims, demands, liabilities, losses, causes of action, awards, fines, penalties, litigation, administrative proceedings and investigations, costs and expenses, and attorney fees (each, an "Indemnifiable Loss") asserted against or incurred by any of the Indemnified Parties arising out of, resulting from or based upon (a) a breach by the Indemnifying Party of its obligations under this Agreement, (b) claims of bodily injury or death of any person or damage to real and/or tangible personal property caused by the negligence or willful misconduct of the Indemnifying Party and its Affiliates and their respective directors, officers, employees, principals, representatives, agents or contractors during the Term, or (c) the acts or omissions of the Indemnifying Party and its Affiliates and their respective directors, officers, employees, principals, representatives, agents or contractors during the Term.

7.2 No Consequential Damages. Neither Party shall be liable to the other Party under this Agreement (by way of indemnification, damages or otherwise) for any indirect, incidental, exemplary, punitive, special or consequential damages, except in the case of gross negligence or willful misconduct.

7.3 Cooperation Regarding Claims. If an Indemnified Party receives notice or has knowledge of any Indemnifiable Loss that may result in a claim for indemnification by such Indemnified Party against an Indemnifying Party pursuant to this Section 7, such Indemnified Party shall as promptly as possible give the Indemnifying Party notice of such Indemnifiable Loss, including a reasonably detailed description of the facts and circumstances relating to such Indemnifiable Loss, a complete copy of all notices, pleadings and other papers related thereto, and in reasonable detail the basis for its claim for indemnification with respect thereto. Failure to promptly give such notice or to provide such information and documents shall not relieve the Indemnifying Party from the obligation hereunder to respond to or defend the Indemnified Party against such Indemnifiable Loss unless such failure shall materially diminish the ability of the Indemnifying Party to respond to or to defend the Indemnified Party against such Indemnifiable Loss. The Indemnifying Party, upon its acknowledgment in writing of its obligation to indemnify the Indemnified Party in accordance with this Section 7, shall be entitled to assume the defense or to represent the interest of the Indemnified Party with respect to such Indemnifiable Loss, which shall include the right to select and direct legal counsel and other consultants, appear in proceedings on behalf of such Indemnified Party and to propose, accept or reject offers of settlement, all at its sole cost. If and to the extent that any such settlement is reasonably likely to involve injunctive, equitable or prospective relief or materially and adversely affect the Indemnified Party's business or operations other than as a result of money damages or other money payments, then such settlement will be subject to the reasonable approval of the Indemnified Party. Nothing herein shall prevent an Indemnified Party from retaining its own legal counsel and other consultants and participating in its own defense at its own cost and expense.

Section 8 - Contract Managers; Dispute Resolution.

8.1 LG&E/KU Contract Manager. LG&E/KU shall appoint an individual (the "LG&E/KU Contract Manager") who shall serve as the primary LG&E/KU representative under this Agreement. The LG&E/KU Contract Manager shall (a) have overall responsibility for managing and coordinating the performance of LG&E/KU's obligations under this Agreement, and (b) be authorized to act for and on behalf of LG&E/KU with respect to all matters relating to this Agreement. Notwithstanding the foregoing, the LG&E/KU Contract Manager may, upon prior written notice to the Reliability Coordinator, delegate such of his or her responsibilities to other LG&E/KU employees, as the LG&E/KU Contract Manager deems appropriate. LG&E/KU may, upon prior written notice to the Reliability Coordinator, change the LG&E/KU Contract Manager.

8.2 Reliability Coordinator Contract Manager. The Reliability Coordinator shall appoint, among the Key Personnel identified in Attachment C, an individual (the "Reliability Coordinator Contract Manager") who shall serve as the primary Reliability Coordinator representative under this Agreement. The Reliability Coordinator Contract Manager shall (a) have overall responsibility for managing and coordinating the performance of the Reliability Coordinator's obligations under this Agreement, and (b) be authorized to act for and on behalf of the Reliability Coordinator with respect to all matters relating to this Agreement. Notwithstanding the foregoing, the Reliability Coordinator Contract Manager may, upon prior written notice to LG&E/KU, delegate such of his or her responsibilities to other Key Personnel, as the Reliability Coordinator Contract Manager deems appropriate. The Reliability Coordinator may, upon prior written notice to LG&E/KU, change the Reliability Coordinator Contract Manager. For the avoidance of doubt, LG&E/KU shall not have an approval or consent right with respect to the selection of the Reliability Coordinator Contract Manager.

8.3 Resolution of Disputes. Any dispute, claim or controversy between the Parties arising out of or relating to this Agreement (each, a "Dispute") shall be resolved in accordance with the procedures set forth in this Section 8.3; provided, however, that this Section 8.3 shall not apply to Disputes arising from or relating to (a) the amount of compensation to be paid by LG&E/KU pursuant to the last sentence of Section 3.1, which shall be resolved pursuant thereto, or (b) confidentiality or intellectual property rights (in which case either Party shall be free to seek available legal or equitable remedies).

8.3.1 Notice of Dispute. Each Party shall provide written notice to the other party of any Dispute, including a description of the nature of the Dispute.

8.3.2 Dispute Resolution by Contract Managers. Any Dispute shall first be referred to the LG&E/KU Contract Manager and the Reliability Coordinator Contract Manager, who shall negotiate in good faith to resolve the Dispute.

8.3.3 Dispute Resolution by Executive Management Representatives. If the Dispute is not resolved within fifteen (15) days of being referred to the LG&E/KU Contract Manager and the Reliability Coordinator Contract Manager pursuant to Section 8.3.2, then each Party shall have five (5) days to appoint an executive management representative who shall negotiate in good faith to resolve the Dispute.

8.3.4 Exercise of Remedies at Law or in Equity. If the Parties' executive management representatives are unable to resolve the Dispute within thirty (30) days of their appointment, then each Party shall be free to pursue any remedies available to it and to take any action in law or equity that it believes necessary or convenient in order to enforce its rights or cause to be fulfilled any of the obligations or agreements of the other Party.

8.4 LG&E/KU Rights Under FPA Unaffected. Nothing in this Agreement is intended to limit or abridge any rights that LG&E/KU may have to file or make application before FERC under Section 205 of the FPA to revise any rates, terms or conditions of the OATT or any other FPA jurisdictional agreement.

8.5 Reliability Coordinator Rights Under the TVA Act and FPA Unaffected. Nothing in this Agreement is intended to limit or abridge any rights that the Reliability Coordinator may have under the TVA Act or the FPA, nor to require the Reliability Coordinator to violate the area limitations set forth in the TVA Act.

8.6 Statute of Limitations; Continued Performance. The Parties agree to waive the applicable statute of limitations during the period of time that the Parties are seeking to resolve a Dispute pursuant to Sections 8.3.2 and 8.3.3, and the statute of limitations shall be tolled for such period. The Parties shall continue to perform their obligations under this Agreement during the resolution of a Dispute.

Section 9 - Insurance.

9.1 Requirements. The Reliability Coordinator shall provide and maintain during the Term insurance coverage in the form and with minimum limits of liability as specified below, unless otherwise agreed to by the Parties.

9.1.1 Worker's compensation insurance in accordance with the Federal Employees Compensation Act (FECA).

9.1.2 Commercial general liability or equivalent insurance with a combined single limit of not less than $1,000,000 per occurrence. Such insurance shall include products/completed operations liability, owners protective, blanket contractual liability, personal injury liability and broad form property damage.

9.2 Insurance Matters. All insurance coverages required pursuant to Section 9.1 shall (a) be provided by insurance companies that have a Best Rating of A or higher, (b) provide that LG&E/KU is an additional insured (other than the workers' compensation insurance), (c) provide that LG&E/KU will receive at least thirty (30) days written notice from the insurer prior to the cancellation or termination of or any material change in any such insurance coverages, and (d) include waivers of any right of subrogation of the insurers thereunder against LG&E/KU. Certificates of insurance evidencing that the insurance required by Section 9.1 is in force shall be delivered by the Reliability Coordinator to LG&E/KU prior to the Effective Date.

9.3 Compliance. The Reliability Coordinator shall not commence performance of any Functions until all of the insurance required pursuant to Section 9.1 is in force, and the necessary documents have been received by LG&E/KU pursuant to Section 9.2. Compliance with the insurance provisions in Section 9 is expressly made a condition precedent to the obligation of LG&E/KU to make payment for any Functions performed by the Reliability Coordinator under this Agreement. The minimum insurance requirements set forth above shall not vary, limit or waive the Reliability Coordinator's legal or contractual responsibilities or liabilities under this Agreement.

Section 10 - Confidentiality.

10.1 Definition of Confidential Information. For purposes of this Agreement, "Confidential Information" shall mean, in respect of each Party, all activities by such Party and information and documentation of such Party, whether disclosed to or accessed by the other Party, in each case, in connection with this Agreement; provided, however, that the term "Confidential Information" shall not include information that: (a) is independently developed by the recipient, as demonstrated by the recipient's written records, without violating the disclosing Party's proprietary rights; (b) is or becomes publicly known (other than through unauthorized disclosure); (c) is disclosed by the owner of such information to a third party free of any obligation of confidentiality; (d) is already known by the recipient at the time of disclosure, as demonstrated by the recipient's written records, and the recipient has no obligation of confidentiality other than pursuant to this Agreement or any confidentiality agreements between the Parties entered into before the Effective Date; or (e) is rightfully received by a Party free of any obligation of confidentiality.

10.2 Protection of Confidential Information. All Confidential Information shall be held in confidence by the recipient to the same extent and in at least the same manner as the recipient protects its own confidential information, and such Confidential Information shall be used only for purposes of performing obligations under this Agreement. Except as otherwise provided in Section 10.4, neither Party shall disclose, publish, release, transfer or otherwise make available Confidential Information of, or obtained from, the other Party in any form to, or for the use or benefit of, any person or entity without the disclosing Party's prior written consent. Each Party shall be permitted to disclose relevant aspects of the other Party's Confidential Information to its officers, directors, agents, professional advisors, contractors, subcontractors and employees and to the officers, directors, agents, professional advisors, contractors, subcontractors and employees of its Affiliates, to the extent that such disclosure is reasonably necessary for the performance of its duties and obligations or the determination, preservation or exercise of its rights and remedies under this Agreement; provided, however, that the recipient shall take all reasonable measures to ensure that Confidential Information of the disclosing Party is not disclosed or duplicated in contravention of the provisions of this Agreement by such officers, directors, agents, professional advisors, contractors, subcontractors and employees. The obligations in this Section 10 shall not restrict any disclosure pursuant to any local, state or federal governmental agency or authority if such release is necessary to comply with applicable laws, governmental regulations or orders of regulatory bodies or courts; provided that, other than in respect of disclosures pursuant to Section 10.4, the recipient shall give prompt notice to the disclosing Party in reasonable time to exercise whatever legal rights the disclosing Party may have to prevent or limit such disclosure. Further, the recipient shall cooperate with the disclosing Party in preventing or limiting such disclosure.

10.3 NERC Data Confidentiality Agreement. In addition to, and not in limitation of, the confidentiality restrictions in Section 10.2, each Party shall sign the NERC Data Confidentiality

Agreement and shall treat all Confidential Information as transmission operations and transmission system information pursuant to the NERC Data Confidentiality Agreement.

10.4 FERC Requests for Confidential Information. Notwithstanding anything in this Agreement to the contrary, if FERC or its staff, during the course of an investigation or otherwise, requests information from the Reliability Coordinator related to services provided by the Reliability Coordinator to LG&E/KU that the Reliability Coordinator is otherwise required to maintain in confidence pursuant to this Agreement, the Reliability Coordinator shall provide the requested information to FERC or its staff within the time provided for in the request for information. In providing such information to FERC or its staff, the Reliability Coordinator shall, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. The Reliability Coordinator shall notify LG&E/KU when it is notified by FERC or its staff that a request for public disclosure of, or decision to publicly disclose, confidential information has been received, at which time either the Reliability Coordinator or LG&E/KU may respond before such information is made public, pursuant to 18 C.F.R. § 388.112.

Section 11 - Force Majeure.

11.1 Neither Party shall be liable to the other Party for any failure or delay of performance hereunder due to causes beyond such Party's reasonable control, which by the exercise of reasonable due diligence such Party is unable, in whole or in part, to prevent or overcome (a "Force Majeure"), including acts of God, act of the public enemy, fire, explosion, vandalism, cable cut, storm or other catastrophes, weather impediments, national emergency, insurrections, riots, wars or any law, order, regulation, direction, action or request of any government or authority or instrumentality thereof. Neither Party shall be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure, except for the obligation to pay any amount when due, provided that the affected Party:

11.1.1 gives notice to the other Party of the event or circumstance giving rise to the event of Force Majeure;

11.1.2 affords the other Party reasonable access to information about the event or circumstances giving rise to the event of Force Majeure;

11.1.3 takes commercially reasonable steps to restore its ability to perform its obligations hereunder as soon as reasonably practicable, provided that the affected Party shall not be obligated to take any steps that are not otherwise in accordance with Good Utility Practice; and

11.1.4 exercises commercially reasonable efforts to perform its obligations hereunder.

Section 12 - Reporting; Audit.

12.1 Reporting. The Reliability Coordinator shall make regular reports to FERC and LG&E/KU's retail regulators as may be required by applicable law and regulations or as may be requested by such authorities.

12.2 Books and Records. The Reliability Coordinator shall maintain full and accurate books and records pertinent to this Agreement, and the Reliability Coordinator shall maintain such books and records for three (3) years following the expiration or early termination of this Agreement or longer if necessary to resolve a pending Dispute. LG&E/KU will have the right, at reasonable times and under reasonable conditions, to inspect and audit, or have an independent third party inspect and audit, the Reliability Coordinator's operations and books to (a) ensure compliance with this Agreement, (b) verify any cost claims or other amounts due hereunder, and (c) validate the Reliability Coordinator's internal controls with respect to the performance of the Functions. The Reliability Coordinator shall maintain an audit trail, including all original transaction records, of all financial and non-financial transactions resulting from or arising in connection with this Agreement as may be necessary to enable LG&E/KU or the independent third party, as applicable, to perform the foregoing activities. LG&E/KU shall be responsible for any costs and expenses incurred in connection with any such inspection or audit, unless such inspection or audit discovers that LG&E/KU was charged inappropriate or incorrect costs and expenses, in which case, the Reliability Coordinator shall be responsible for a percentage of the costs and expenses incurred in connection with such inspection or audit equal to the percentage variance by which LG&E/KU was charged inappropriate or incorrect costs and expenses. The Reliability Coordinator shall provide reasonable assistance necessary to enable LG&E/KU or an independent third party, as applicable, and shall not be entitled to charge LG&E/KU for any such assistance. Amounts incorrectly or inappropriately invoiced by the Reliability Coordinator to LG&E/KU, whether discovered prior to or subsequent to payment by LG&E/KU, shall be adjusted or reimbursed to LG&E/KU by the Reliability Coordinator within twenty (20) days of notification by LG&E/KU to the Reliability Coordinator of the error in the invoice.

12.3 Regulatory Compliance. The Reliability Coordinator shall comply with all reasonable requests by LG&E/KU to comply with Section 404 of the Sarbanes-Oxley Act and related regulatory requirements. LG&E/KU may hire, at its expense, or LG&E/KU may direct the Reliability Coordinator to hire, at LG&E/KU expense, an independent auditor to review, audit and prepare audit reports associated with the Reliability Coordinator's controls and systems relating to the Functions and LG&E/KU's financial statements and reports, in accordance with SAS No. 70, Type II. Such reports may not be required more frequently than twice per Contract Year. The Reliability Coordinator shall notify LG&E/KU prior to or at the time of any significant or material change to any internal process or financial control of the Reliability Coordinator that would or might impact the Functions performed for or on behalf of LG&E/KU or that would, or might, have a significant or material effect on such process's mitigation of risk or upon the integrity of LG&E/KU's financial reporting or disclosures and provide sufficient details of the change so as to enable LG&E/KU and/or its independent auditors to review the change and evaluate its impact on its internal controls and financial reporting. The Reliability Coordinator shall cooperate with the independent auditors and LG&E/KU to enable the preparation of the reports necessary to comply with Section 404 of the Sarbanes-Oxley Act, consistent with the other provisions of this Agreement.

Section 13 - Independent Contractor.

The Reliability Coordinator shall be and remain during the Term an independent contractor with respect to LG&E/KU, and nothing contained in this Agreement shall be (a) construed as inconsistent with that status, or (b) deemed or construed to create the relationship of principal and agent or employer and employee, between the Reliability Coordinator and LG&E/KU or to make either the Reliability Coordinator or LG&E/KU partners, joint ventures, principals, fiduciaries, agents or employees of the other Party for any purpose. Neither Party shall represent itself to be an agent, partner or representative of the other Party. Neither Party shall commit or bind, nor be authorized to commit or bind, the other Party in any manner, without such other Party's prior written consent. Personnel employed, provided or used by any Party in connection herewith will not be employees of the other Party in any respect. Each Party shall have full responsibility for the actions or omissions of its employees and shall be responsible for their supervision, direction and control.

Section 14 - Taxes.

Each Party shall be responsible for the payment of its own taxes, including taxes based on its net income, employment taxes of its employees, taxes on any property it owns or leases, and sales, use, gross receipts, excise, value-added or other transaction taxes.

Section 15 - Notices.

15.1 Notices. Except as otherwise specified herein, any notice required or authorized by this Agreement shall be deemed properly given to a Party when sent to its designated representative by facsimile or other electronic means (with a confirmation copy sent by United States mail, first-class postage prepaid), by hand delivery, or by United States mail, first-class postage prepaid. The Parties' designated representatives are as follows:

If to LG&E/KU:

Louisville Gas and Electric Company
220 West Main St.
Louisville, Kentucky 40202
Facsimile: (502) 627-4002

And

Kentucky Utilities Company
220 West Main St.
Louisville, Kentucky 40202
Facsimile: (502) 627-4002

If to the Reliability Coordinator:

Tennessee Valley Authority
1101 Market Street, PCC 2A
Chattanooga, Tennessee 37402-2801
Facsimile: (423) 697-4120

15.2 Changes. Either Party may, from time to time, change the names, addresses, facsimile numbers or other notice information set out in Section 15.1 by notice to the other Party in accordance with the requirements of Section 15.1.

Section 16 - Key Personnel; Work Conditions.

16.1 Key Personnel. All Key Personnel shall be properly certified and licensed, if required by law, and be qualified and competent to perform the Functions. The Reliability Coordinator shall provide LG&E/KU prior written notice of the replacement of any Key Personnel.

16.2 Conduct of Key Personnel and Reporting. The Reliability Coordinator agrees to require that the Key Personnel comply with the Reliability Coordinator's employee code of conduct, a current copy of which has been provided to LG&E/KU. The Reliability Coordinator may amend its employee code of conduct at any time, provided that the Reliability Coordinator shall promptly provide the LG&E/KU Contract Manager with a copy of the amended employee code of conduct. If any Key Personnel commits fraud or engages in material violation of the Reliability Coordinator's employee code of conduct, the Reliability Coordinator shall promptly notify LG&E/KU as provided above and promptly remove any such Key Personnel from the performance of the Functions.

16.3 Personnel Screening. The Reliability Coordinator shall be responsible for conducting, in accordance with applicable law (including the Fair Credit Reporting Act, The Fair and Accurate Credit Transactions Act, and Title VII of the Civil Rights Act of 1964), adequate pre-deployment screening of the Key Personnel prior to commencing performance of the Functions. By deploying Key Personnel under this Agreement, the Reliability Coordinator represents that it has completed the Screening Measures (as defined below) with respect to such Key Personnel. To the extent permitted by applicable law, the term "Screening Measures" shall include, at a minimum, a background check including: (a) a Terrorist Watch Database Search; (b) a Social Security Number trace; (c) motor vehicle license and driving record check; and (d) a criminal history check, including, a criminal record check for each county/city and state/country in the employee's residence history for the maximum number of years permitted by law, up to seven (7) years. Unless prohibited by law, if, prior to or after assigning a Key Personnel to perform the Functions, the Reliability Coordinator learns of any information that the Reliability Coordinator considers would adversely affect such Key Personnel's suitability for the performance of the Functions (including based on information discovered from the Screening Measures), the Reliability Coordinator shall not assign the Key Personnel to the Functions or, if already assigned, promptly remove such Key Personnel from performing the Functions and immediately notify LG&E/KU of such action.

16.4 Security. LG&E/KU shall have the option of barring from LG&E/KU's property any Key Personnel whom LG&E/KU determines is not suitable in accordance with the applicable laws pursuant to Sections 16.1 through 16.3.

Section 17 - Miscellaneous Provisions.

17.1 Governing Law. This Agreement and the rights and obligations of the Parties hereunder shall be governed by and construed in accordance with applicable state and federal laws, without regard to the laws requiring the applicability of the laws of another jurisdiction.

17.2 Amendment. This Agreement shall not be varied or amended unless such variation or amendment is agreed to by the Parties in writing.

17.3 Assignment. Neither Party shall sell, assign, or otherwise transfer any or all of its respective rights hereunder, or delegate any or all of its respective obligations under this

Agreement.

17.4 No Third Party Beneficiaries. Nothing in this Agreement is intended to confer any benefits upon any person or entity not a Party to this Agreement. This Agreement is made solely for the benefit of the Parties and nothing herein shall be construed as a stipulation for the benefit of others, and no third party shall be entitled to enforce this Agreement against any Party hereto.

17.5 Waivers. No waiver of any provision of this Agreement shall be effective unless it is signed by the Party against which it is sought to be enforced. The delay or failure by either Party to exercise or enforce any of its rights under this Agreement shall not constitute or be deemed a waiver of that Party's right thereafter to enforce those rights, nor shall any single or partial exercise of any such right preclude any other or further exercise thereof or the exercise of any other right.

17.6 Severability; Renegotiation. The invalidity or unenforceability of any portion or provision of this Agreement shall in no way affect the validity or enforceability of any other portion or provision herein. If any provision of this Agreement is found to be invalid, illegal or otherwise unenforceable, the same shall not affect the other provisions hereof or the whole of this Agreement and shall not render invalid, illegal or unenforceable this Agreement or any of the remaining provisions of this Agreement. If any provision of this Agreement or the application thereof to any person, entity or circumstance, is held by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, or if a modification, condition or other change to this Agreement is imposed by a court or regulatory authority of competent jurisdiction which materially affects the benefits or obligations of the Parties, then the Parties shall in good faith negotiate such amendment or amendments to this Agreement as will restore the relative benefits and obligation of the Parties immediately prior to such holding, modification or condition. If such negotiations are unsuccessful, then either Party may terminate this Agreement pursuant to Section 4.5.1.

17.7 Representations and Warranties. Each Party represents and warrants to the other Party as of the Execution Date and the Effective Date as follows:

17.7.1 Organization. It is duly organized, validly existing and in good standing under the laws of the State in which it was organized or applicable Federal law, and has all the requisite power and authority to own and operate its material assets and properties and to carry on its business as now being conducted and as proposed to be conducted under this Agreement.

17.7.2 Authority. It has the requisite power and authority to execute and deliver this Agreement and, subject to the procurement of applicable regulatory approvals, to perform its obligations under this Agreement. The execution and delivery of this Agreement by it and the performance of its obligations under this Agreement have been duly authorized by all necessary corporate action required on its part.

17.7.3 Binding Effect. Assuming the due authorization, execution and delivery of this Agreement by the other Party, this Agreement constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency or other similar applicable laws affecting creditors' rights generally, and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

17.7.4 Regulatory Approval. It has obtained or will obtain by the Effective Date, any and all approvals of, and acceptances for filing by, and has given or will give any notices to, any applicable federal or state authority, that are required for it to execute, deliver, and perform its obligations under this Agreement.

17.7.5 No Litigation. There are no actions at law, suits in equity, proceedings, or claims pending or, to its knowledge, threatened against it before or by any federal, state, foreign or local court, tribunal, or governmental agency or authority that might materially delay, prevent, or hinder the performance by such entity of its obligations hereunder.

17.7.6 No Violation or Breach. The execution, delivery and performance by it of its obligations under this Agreement do not and shall not: (a) violate its organizational documents; (b) violate any applicable law, statute, order, rule, regulation or judgment promulgated or entered by any applicable federal or state authority, which violation could reasonably be expected to materially adversely affect the performance of its obligations under this Agreement; or (c) result in a breach of or constitute a default of any material agreement to which it is a party.

17.8 Further Assurances. Each Party agrees that it shall execute and deliver such further instruments, provide all information, and take or forbear such further acts and things as may be reasonably required or useful to carry out the purpose of this Agreement and are not inconsistent with the provisions of this Agreement.

17.9 Entire Agreement. This Agreement and the Attachments hereto set forth the entire agreement between the Parties with respect to the subject matter hereof, and supersede all prior agreements, whether oral or written, related to the subject matter of this Agreement, including that certain Reliability Coordinator Agreement, dated as of January 10, 2006, between the Parties. The terms of this Agreement and the Attachments hereto are controlling, and no parole or extrinsic evidence, including to prior drafts and drafts exchanged with any third parties, shall be used to vary, contradict or interpret the express terms, and conditions of this Agreement.

17.10 Good Faith Efforts. Each Party agrees that it shall in good faith take all reasonable actions necessary to permit it and the other Party to fulfill their obligations under this Agreement. Where the consent, agreement or approval of any Party must be obtained hereunder, such consent, agreement or approval shall not be unreasonably withheld, delayed or conditioned. Where a Party is required or permitted to act, or omit to act, based on its opinion or judgment, such opinion or judgment shall not be unreasonably exercised. To the extent that the jurisdiction of any federal or state authority applies to any part of this Agreement or the transactions or actions covered by this Agreement, each Party shall cooperate with the other Party to secure any necessary or desirable approval or acceptance of such authorities of such part of this Agreement or such transactions or actions.

17.11 Time of the Essence. With respect to all duties, obligations and rights of the Parties, time shall be of the essence in this Agreement.

17.12 Interpretation. Unless the context of this Agreement otherwise clearly requires:

17.12.1 all defined terms in the singular shall have the same meaning when used in the plural and vice versa;

17.12.2 the terms "hereof," "herein," "hereto" and similar words refer to this entire Agreement and not to any particular Section, Attachment or any other subdivision of this Agreement;

17.12.3 references to "Section" or "Attachment" refer to this Agreement, unless specified otherwise;

17.12.4 references to any law, statute, rule, regulation, notification or statutory provision shall be construed as a reference to the same as it applies to this Agreement and may have been, or may from time to time be, amended, modified or re-enacted;

17.12.5 references to "includes," "including" and similar phrases shall mean "including, without limitation;"

17.12.6 the captions, section numbers and headings in this Agreement are included for convenience of reference only and shall not in any way affect the meaning or interpretation of this Agreement;

17.12.7 "or" may not be mutually exclusive, and can be construed to mean "and" where the context requires there to be a multiple rather than an alternative obligation; and

17.12.8 references to a particular entity include such entity's successors and assigns to the extent not prohibited by this Agreement.

17.12.9 any capitalized terms used in this Agreement, including the Appendices, that are not defined in this Agreement or in the Appendices, shall have the meaning established in the applicable NERC documentation.

17.13 Joint Effort. Preparation of this Agreement has been a joint effort of the Parties and the resulting document shall not be construed more severely against one of the Parties than against the other and no provision in this Agreement is to be interpreted for or against any Party because that Party or its counsel drafted such provision. Each Party acknowledges that in executing this Agreement its has relied solely on its own judgment, belief and knowledge, and such advice as it may have received from its own counsel, and it has not been influenced by any representation or statement made by the other Party or its counsel not contained in this Agreement.

17.14 Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument, binding upon LG&E/KU and the Reliability Coordinator, notwithstanding that LG&E/KU and the Reliability Coordinator may not have executed the same counterpart.

Section 18 - Confidential Critical Infrastructure Information Protection. Notwithstanding any other applicable confidentiality provisions in this RC Agreement including Section 10 above, the following provisions of this Section 18 shall apply with respect to LG&E/KU's Protected Assets and Information. "LG&E/KU's Protected Assets and Information" is defined as: (i) LG&E/KU's Critical Cyber Assets, (ii) LG&E/KU's Cyber Assets used in access control and monitoring of Company's Electronic Security Perimeter(s), (iii) LG&E/KU's Cyber Assets that authorize or log access to LG&E/KU's Physical Security Perimeter(s) or (iv) any information relating to LG&E/KU's Critical Cyber Assets, including, without limitation, operational procedures, Critical Asset lists, Critical Cyber Asset lists, network topology or similar diagrams, floor plans of computer centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, security configuration information, and any other confidential information relating to the reliability or operability of the Bulk Electric System and information generated or otherwise developed by the Reliability Coordinator in connection with its performance of the Reliability Coordinator functions that constitute or are otherwise related to LG&E/KU's Protected Assets and Information (collectively, "Confidential Critical Infrastructure Information"). The Reliability Coordinator shall not disclose any Confidential Critical Infrastructure Information (which will be clearly marked or otherwise identified by LG&E/KU as Confidential Critical Infrastructure Information) to any person or entity, except strictly on a need-to-know basis, and shall take all necessary actions to protect the Confidential Critical Infrastructure Information, including, without limitation, ensuring that appropriate electronic and/or password access controls are in place if such Confidential Critical Infrastructure Information is stored on shared drives or systems, encrypting all such information stored on laptops or removable media (such as a USB drive), and maintaining any such hard copy information in a secure, locked storage container and not permitting any unauthorized individual to view, handle or possess such information. The Reliability Coordinator shall provide to LG&E/KU a list of all the Reliability Coordinator employees, subcontractors or other persons associated with the Reliability Coordinator with access to any Confidential Critical Infrastructure Information when and as requested by LG&E/KU. The Reliability Coordinator will provide notification by contacting the LG&E/KU's NERC Compliance representative identified below immediately upon becoming aware that it has disclosed any Confidential Critical Infrastructure Information in violation of this Section 18. The Reliability Coordinator shall ensure that each recipient of any Confidential Critical Infrastructure Information understands and complies with the requirements to protect Confidential Critical Infrastructure Information from inappropriate disclosure as set forth in this Section 18. Notwithstanding anything to the contrary in the Contract, with respect to any Confidential Critical Infrastructure Information, the restrictions set forth in this Section 18 shall remain in effect indefinitely from the date such Confidential Critical Infrastructure Information was first disclosed to or obtained or discovered by the Reliability Coordinator. The Reliability Coordinator shall, upon request and as directed by LG&E/KU, promptly return to LG&E/KU, or otherwise properly dispose of, any and all Confidential Critical Infrastructure Information that is in the possession of the Reliability Coordinator or any of its employees or subcontractors.

The parties have caused this Reliability Coordinator Agreement to be executed by their duly authorized representatives as of the dates shown below.

LOUISVILLE GAS AND ELECTRIC COMPANY

/s/ Tom Jessee

Name: Tom Jessee
Title: Vice President, Transmission
Date: 8/25/14

KENTUCKY UTILITIES COMPANY

/s/ Tom Jessee

Name: Tom Jessee
Title: Vice President, Transmission
Date: 8/25/14

TENNESSEE VALLEY AUTHORITY

/s/ Timothy E. Ponseti

Name: Timothy E. Ponseti
Title: Vice President, Transmission Operations & Power Supply
Date: 8-25-2014

ATTACHMENT A
TO THE RELIABILITY COORDINATOR AGREEMENT

DESCRIPTION OF THE PRIMARY FUNCTIONS

The Reliability Coordinator is responsible for bulk transmission reliability and power supply reliability functions. Bulk transmission reliability functions include reliability analysis, loading relief procedures, re-dispatch of generation and ordering curtailment of transactions and/or load. Power supply reliability functions include monitoring Balancing Authority Area performance and ordering the Balancing Authority to take actions, including load curtailment and increasing/decreasing generation in situations where an imbalance between generation and load places the system in jeopardy. The procedures to be followed by the Reliability Coordinator shall be consistent with those of NERC and are spelled out in the NERC Approved Reliability Plan for the TVA Reliability Coordination Area and TVA Standard Procedures and Policies.

I. Reliability Coordinator General Functions:

The Reliability Coordinator shall perform the following functions:

a) Serving as NERC designated reliability coordinator and represent the TVA Reliability Area at the NERC and Regional Reliability Council level.

b) Implementing applicable NERC and regional reliability criteria initiatives, such as maintaining a connection to NERC's Interregional Security Network ("ISN"), day-ahead load-flow analysis, transmission loading relief procedures, and information exchange.

c) Developing and coordinating with the Reliability Coordination Advisory Committee ("RCAC") new Reliability Coordinator Procedures and revisions to existing Reliability Coordinator Procedures.

d) Exchanging timely, accurate, and relevant Transmission System information with LG&E/KU, the ITO, and with other reliability coordinators.

e) Developing and maintaining system models and tools needed to perform analysis needed to develop operational plans.

f) Coordinating with neighboring reliability coordinators and other operating entities as appropriate to ensure regional reliability.

g) All other reliability coordinator functions as required for compliance with applicable NERC Reliability Standards and Regional Reliability Council standards, as the same may be amended or modified from time to time.

II. Real-time Operations:

A. Reliability Coordinator Functions:

The Reliability Coordinator shall perform the following functions:

a) Monitoring, analyzing, and coordinating the reliability of LG&E/KU's facilities and interfaces with other Balancing Authorities, Transmission Operators, and other reliability coordinators.

b) Performing analyses to develop an evaluation of system conditions. LG&E/KU will provide necessary information (e.g., outages and transactions) and Transmission System conditions, as applicable, to the Reliability Coordinator in accordance with applicable NERC Reliability Standards. The results of these analyses will be provided to LG&E/KU and neighboring reliability coordinators in accordance with applicable NERC Standards and Regional Reliability Council Standards.

c) Determining, directing, and documenting appropriate actions to be taken by LG&E/KU, the ITO and Reliability Coordinator in accordance with the NERC Reliability Standards, including curtailment of transmission service or energy schedules, re-dispatch of generation and load shedding as necessary to alleviate facility overloads and abnormal voltage conditions, and other circumstances that affect interregional bulk power reliability.

d) Coordinating transmission loading relief and voltage correction actions with LG&E/KU and with other reliability coordinators.

B. LG&E/KU Responsibilities:

LG&E/KU shall have the following responsibilities:

a) Ensuring appropriate telemetry and providing Reliability Coordinator real-time operational information for monitoring.

b) Receiving from the Reliability Coordinator all reliability alerts for TVA Reliability Area and neighboring reliability coordinators.

c) Following Reliability Coordinator directives for corrective actions (e.g., curtailments or load shedding) during system emergencies or to implement TLR procedures.

d) Receiving from Reliability Coordinator all notices regarding Transmission System limitations or other reliability issues, as appropriate.

III. Forward Operations:

A. Reliability Coordinator Functions:

The Reliability Coordinator shall perform the following functions:

a) Performing analyses and develop an evaluation of the expected next-day Transmission System operations. The results of these analyses shall be provided to LG&E/KU, the ITO and neighboring reliability coordinators in accordance with applicable NERC Reliability Standards and Regional Reliability Council Standards.

b) Performing analysis of planned transmission and generation outages and coordination of outages with NERC, participants in reliability coordination agreements, and other reliability coordinators as appropriate and as required by NERC. This entails analysis and coordination of planned outages which are beyond next day and intra-day outages.

c) Analyzing and approving all planned maintenance schedules on facilities 100kV and above and planned maintenance of generation facilities submitted by LG&E/KU in conjunction with other work on the regional transmission grid to determine the impact of LG&E/KU’s planned maintenance schedule on the reliability of the facilities under TVA's purview as Reliability Coordinator, and the purview of neighboring reliability coordinators, and any other relevant effects; and coordinate impacts on available transfer capability with the ITO.

d) Coordinating, as required by either NERC or other agreements, planned maintenance schedules with all adjacent reliability coordination areas and/or Balancing Authority Areas and Transmission Providers; as well as the ITO.

B. <u>LG&E/KU Responsibilities</u>:

LG&E/KU shall have the following responsibilities:

a) Providing generation-related information (e.g., outages and transactions) and expected Transmission System conditions (e.g., transmission facility outages and transactions), as applicable, to the Reliability Coordinator for the next-day operation in accordance with applicable NERC Reliability Standards and Regional Reliability Council standards.

b) Submitting facility ratings and operational data for all generators and transmission facilities in the LG&E/KU footprint.

c) Coordinating with the ITO and submitting to the Reliability Coordinator generation dispatch information for the LG&E/KU footprint and following Reliability Coordinator directives regarding dispatch adjustments to mitigate congestion.

d) Submitting to the Reliability Coordinator generation operation plans and commitments for reliability analysis.

e) Submitting to the Reliability Coordinator transmission maintenance plans for reliability analysis.

f) Following Reliability Coordinator directives to revise transmission maintenance plans as required to ensure grid reliability.

g) Receiving from Reliability Coordinator all notices regarding reliability analyses for the TVA Reliability Area as well as neighboring reliability coordinators.

h) Representing LG&E/KU on the RCAC and in all RCAC deliberations.

IV. Regional Congestion Management

For the purposes of this section IV, capitalized terms will have the definitions used in the Congestion Management Process ("CMP"), unless otherwise noted in this section IV.

A. Reliability Coordinator Functions:

The following functions to be performed by the Reliability Coordinator shall be performed in conjunction with the functions to be performed by the Independent Transmission Operator under the Independent Transmission Organization Agreement and will fully incorporate the LG&E/KU operations into the procedures and protocols governing other facilities in the Reliability Coordinator's Reliability Area in accordance with the CMP:

a) Identifying Coordinated Flowgates and determination of flowgates requiring Reciprocal Coordination (twice annually).

b) Performing Historic Firm Flow Calculations -- implement transmission service reservation set and designated resources provided by LG&E/KU for established freeze date; calculate historic firm flow values and ratios for all coordinated flowgates on LG&E/KU's system (bi-annually).

c) Developing reciprocal coordination agreements that establish how each Operating Entity will consider its own flowgates as well as the usage of other Operating Entities when it determines the amount of flowgate or constraint capacity remaining. This process will include both operating horizon determination as well as forward looking capacity allocation.

d) Implementing AFC Process -- determine AFC attribute requirements; obtain NNL Impact Data; implement Allocation Calculation Process; implement AFC calculation process.

e) The Reliability Coordinator will provide the ITO flowgate AFCs on an hourly basis and flowgate allocations on a daily basis.

B. <u>LG&E/KU Responsibilities</u>:

LG&E/KU is obligated to uphold the terms and conditions of the CMP, and providing the Reliability Coordinator with the information and support it needs in order to carry out its duties as LG&E/KU 's Reliability Coordinator. LG&E/KU shall have the following responsibilities. LG&E/KU will be responsible for coordinating with the ITO and providing Transmission System data to the Reliability Coordinator including, but not limited to:

Operating information:

(i) Transmission Service Reservations;
(ii) Load forecast requirements;
(iii) Flowgates requirements;
(iv) AFC data requirements;
(v) PSSE Models Requirements;
(vi) Designated Network Resources requirements;

(vii) Jointly owned units;
(viii) Dynamic schedules;
(ix) NNL allocations requirements; and,
(x) NNL Evaluator Requirements.

Projected operating information:

(i) Unit commitment/merit order;
(ii) Firm purchase and sales (including grandfathered agreements);
(iii) Independent power producer information including current operating level, projected operating levels, Scheduled Outage start and end dates;
(iv) Planned and actual operational start-up dates for any permanently added, removed, or significantly altered transmission segments; and
(v) Planned and actual start-up testing and operational start-up dates for any permanently added, removed, or significantly altered generation units.

C. <u>ITO Responsibilities</u>:

The ITO shall have the following responsibilities in support of the Congestion Management Process (“CMP”):

a) Providing to the Reliability Coordinator all transmission facility plans and facility upgrade schedules.

b) Providing to the Reliability Coordinator the status of all transmission service requests and all new transmission service agreements.

c) Receiving from the Reliability Coordinator all flowgate AFCs on an hourly basis and flowgate allocations on a daily basis.

d) Converting flowgate information provided by the Reliability Coordinator to ATC values for posting on OASIS and for analyzing TSRs.

e) Implementing CMP business rules for AFC vs. ASTFC.

f) Honoring all AFC allocations and AFC over-rides from other CMP participants in the evaluation and granting of transmission service.

V. <u>Reliability Coordination</u>

A. <u>Reliability Coordinator Functions</u>:

The Reliability Coordinator will ensure a long-term (one year and beyond) plan is available for adequate resources and transmission within the TVA Reliability Area. The Reliability Coordinator will integrate the Annual Plan provided by the ITO with plans of other operating entities in the Reliability Coordination Area and assess the plans to ensure those plans meet reliability standards.

The Reliability Coordinator will advise the ITO of solutions to plans that do not meet those standards. The Reliability Coordinator will then coordinate the Reliability Area Plan with those of neighboring reliability coordinators and Planning Coordinators to ensure wide-area grid reliability.

These functions include:

a) Integrating the transmission and resource (demand and capacity) system models provided by the ITO with those of other Reliability Coordinator Area operating entities to ensure Transmission System reliability and resource adequacy.

b) Applying methodologies and tools to assess and analyze the Transmission System's expansion plans and the resource adequacy plans.

c) Collecting all information and data required for modeling and evaluation purposes.

d) Integrating and verifying that the respective plans of the Resource Planners and Transmission Planners within the TVA Reliability Area meet reliability standards.

e) Coordinating the Reliability Coordinator Area plan with neighboring Reliability Coordinators for review, as appropriate.

f) Integrating the Reliability Coordinator Area plan with neighboring Planning Coordinators/reliability coordinators' plans to provide a broad multi-regional bulk system planning view.

B. LG&E/KU Responsibilities:

LG&E/KU shall have the following responsibilities:

a) Providing to the Reliability Coordinator demand and energy end-use customer forecasts, capacity resources, and demand response programs.

b) Providing to the Reliability Coordinator generator unit performance characteristics and capabilities.

c) Providing to Reliability Coordinator long-term capacity purchases and sales.

ATTACHMENT B

DIVISION OF RESPONSIBILITIES FOR THE PLANNING FUNCTION

Overview

This Attachment B to the Reliability Coordinator Agreement is designed to provide a division of responsibilities between LG&E/KU, the ITO and the Reliability Coordinator. Long-term Transmission Planning for LG&E/KU's footprint will be conducted as an iterative process as follows: 1) LG&E/KU will develop the long-term Annual Transmission Plan ("Annual Plan") and submit the Annual Plan to the ITO for initial approval; 2) The ITO will review and conduct an engineering assessment of the Annual Plan; and if it is approved, the ITO will submit the Annual Plan to the Reliability Coordinator; 3) The Reliability Coordinator will conduct a regional assessment of the Annual Plan, subject to the conditions below; 4) The Reliability Coordinator will submit any changes based on its regional assessment to the ITO for final review and approval. The ITO will ensure that transmission planning on the Transmission Owner's system is done on an independent, non-discriminatory basis. This process is further detailed below.

1. Plan Development by LG&E/KU

LG&E/KU will be responsible for the following tasks:

1.1 **System Models for Transmission Planning**. LG&E/KU will develop and maintain all transmission and resource (demand and capacity) system models, to evaluate Transmission System performance and resource adequacy. As part of these duties LG&E/KU is responsible for:

1.1.1 Creating the Base Case Model for the Transmission System. This Model will include all existing long-term, firm uses of the Transmission System, including: (i) Network Integration Transmission Service; (ii) firm transmission service for LG&E/KU's Native Load; (iii) Long-Term Point-to-Point Transmission Service; and (iv) firm transmission service provided in accordance with grandfathered agreements. The Base Case Model will be developed pursuant to the modeling procedures used in developing the NERC multi-regional and Reliability*First* regional models.

1.1.2 Providing the Base Case Model to the ITO for review and approval according to the iterative process outlined in the overview to this Attachment B.

1.1.3 Maintaining other transmission models including, but not limited to steady-state, dynamic and short circuit models.

1.2 **Assess, develop, and document Resource and Transmission Expansion plans**. LG&E/KU will assess, develop, and document Resource and Transmission Expansion plans including the Annual Plan. These plans include the following responsibilities:

1.2.1 Maintaining and apply methodologies and appropriate tools for the development, analysis and simulation of the Transmission System in the assessment and development of transmission expansion plans and the analysis and development of resource adequacy plans.

1.2.2 Developing a long-term (generally one year and beyond) plan for the reliability (adequacy) of the Transmission System.

1.2.3 Defining system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability standards.

1.2.4 Developing and report, as appropriate, on the Annual Plan for assessment and compliance with reliability standards.

1.2.5 Monitoring and report, as appropriate, its Annual Plan implementation.

1.3 **Information**. LG&E/KU will define, collect and develop information required for planning purposes, including:

1.3.1 **Transmission facility characteristics and ratings.** Collect and maintain specific transmission information regarding characteristics of transmission facilities, lines, equipment, and methodologies, for determining the appropriate thermal ratings of circuits and transformers, including information on transmission line design temperature, voltage and stability limits and other transformer test data.

1.3.2 **Demand and energy end-use customer forecasts, capacity resources, and demand response programs.** Including:

i. Load forecasts for all existing delivery points for the following ten years, including transmission (wholesale and retail) connected substations and distribution substations, and coincident and noncoincident peak demands and power factor at each delivery point;

ii. Plans for new delivery points for the following ten years;

iii. Resource plans for the following 10 years;

iv. Expectations for market access to on- and off-system generation resources;

v. All planned on-system distributed generation resources; and

vi. Information on all interruptible loads.

1.3.3 **Generator unit performance characteristics and capabilities.** LG&E/KU shall provide the ITO with all necessary data, information, and applicable requirements that govern the operation of any generating facilities interconnected with the Transmission System, as the ITO may require for performance of its various functions. LG&E/KU shall submit and coordinate generator unit schedules as necessary to permit the ITO to assess transmission transfer capability and to permit the Reliability Coordinator to assess transmission reliability. LG&E/KU shall submit, on an annual basis, data concerning projected loads, designated network resources, generation and transmission maintenance schedules, and other such operating data as the ITO may require for performance its various functions.

1.3.4 **Long-term capacity purchases and sales**. LG&E/KU will maintain a list of all long-term capacity purchases and sales and include this information in its model development and the Annual Plan.

2 ITO Review and Assessment

The ITO will be responsible for the following tasks:

2.1 Independently reviewing and approving LG&E/KU's Planning Guidelines. If the ITO concludes that additional explanatory detail is required, LG&E/KU will modify the appropriate business practice documents to include the additional detail. The ITO will ensure that the final versions of the Planning Criteria are posted on OASIS;

2.2 Reviewing and approving LG&E/KU's Base Case Model; reviewing, evaluating, and commenting on the Annual Plan as developed by LG&E/KU. This review and evaluation will be based on all applicable planning criteria and statewide or multi-state transmission planning requirements;

2.3 Monitoring LG&E/KU's transmission facility ratings based on access to data necessary to evaluate such ratings;

2.4 Performing an Independent assessment of the Transmission System using the Planning Guidelines and the Base Case Model. As part of this assessment, the ITO will independently evaluate whether: (i) LG&E/KU's Annual Plan complies with the Planning Guidelines and the Base Case Model; and (ii) whether there are upgrade projects in the Annual Plan that are not necessary to meet the Planning Guidelines and the Base Case Model;

2.5 Holding a Transmission Planning Conference to gather input and consider the planning process and LG&E/KU's Annual Plan; and

2.6 Providing LG&E/KU with its conclusions regarding the reliability assessment and evaluation of the Annual Plan, including any outstanding issues that the ITO believes LG&E/KU should address. LG&E/KU will have the opportunity to review the ITO's conclusions and may submit a revised Annual Plan and supporting documentation to the ITO to address any outstanding issues. Once the Annual Plan has been finalized by LG&E/KU, the ITO will submit the Annual Plan to the Reliability Coordinator for regional coordination.

3 Regional Coordination

The Reliability Coordinator will be responsible for the following tasks:

3.1 Integrating and verifying that the respective plans for the regional area meet reliability standards.

3.2 Identifying and reporting on potential Transmission System and resource adequacy deficiencies in the regional area, and provide alternate plans that mitigate these deficiencies.

3.3 Reviewing and reporting, as appropriate, on LG&E/KU's Annual Plan for assessment and compliance with reliability standards within their regional area.

3.4 Notifying impacted transmission entities within their regional area of any planned transmission changes that may impact their facilities.

3.5 Submitting Annual Plan, including any changes based on the regional coordination, to the ITO for final approval.

4 Final Review and Assessment

4.1 The ITO shall have final review and assessment of all plans. If the ITO cannot approve a plan after regional coordination, then the ITO will return the plan to LG&E/KU for further development as appropriate. The process for final approval of any previously rejected plan will follow the same iterative process as outlined above.

4.2 The ITO will post LG&E/KU's finalized Annual Plan on OASIS.

5 Implementation of Plan and Construction of Upgrades

5.1 LG&E/KU is responsible for the implementation of the Annual Plan. LG&E/KU will make a good faith effort to design, certify, and build facilities approved by the ITO in the Annual Plan.

5.2 In the case where the Reliability Coordinator or the ITO does not agree with the Annual Plan, nothing in this Attachment B shall prevent LG&E/KU from constructing those facilities it deems necessary to reliably meet its obligation to serve its Transmission Customers, point-to-point, Network Integration Service, and Native Load Customers.

ATTACHMENT C
TO THE RELIABILITY COORDINATOR AGREEMENT

LIST OF KEY PERSONNEL

TVA Reliability Coordination Services

August 2014

Reliability Authority & Regional Operations
Armando Rodriguez - Senior Manager, Reliability Authority & Regional Operations
Roy Mathai - Project Manager, Operations Readiness
Reliability Operations

Nathan Schweighart - Manager, Reliability Operations
Terry Williams - Specialist Reliability Analysis Operator
Julio Bolano - Specialist Reliability Analysis Operator
Richard Brent Fuller - Specialist Reliability Analysis Operator
Timothy Gleason - Specialist Reliability Analysis Operator
Donald Herring - Specialist Reliability Analysis Operator
Daniel Kehoe - Specialist Reliability Analysis Operator
Thomas Wilk - Specialist Reliability Analysis Operator
William C. Dunn - Reliability Coordinator System Operator
Kevin Grooms - Reliability Coordinator System Operator
Darrell Jones - Reliability Coordinator System Operator
Thomas C. Nance - Reliability Coordinator System Operator
Travis Rackley - Reliability Coordinator System Operator
Brent Taylor - Reliability Coordinator System Operator
Reliability Analysis
Scott Walker - Manager, Reliability Analysis
Timothy Fritch - Electrical Engineer Planning
Marshalia Green - Electrical Engineer Planning
Gary Kobet - Electrical Engineer Planning
Shaun McFarland - Electrical Engineer Planning
Charles Michael McAmis - Electrical Engineer Planning
Jonathan Prater - Electrical Engineer Planning
Matthew Scott Schebler - Electrical Engineer Planning
Joshua Shultz - Electrical Engineer Planning
Justin Baier - Engineering Intern
Ulyana Pugina - Engineering Intern
Advanced Power Applications
Gregory Dooley - Electrical Engineer Power Systems
Alden Bost Jr. - Electrical Engineer Power Systems
Joey Burke - Electrical Engineer Power Systems
Brian Scott - Electrical Engineer Power Systems
David Nordy Jr. - Electrical Engineer Power Systems
Thomas Scott - Engineering Intern
Cyril Shircel - Engineering Intern
Karlee Winkelman - Engineering Intern

EXHIBIT 1
TO THE RELIABILITY COORDINATOR AGREEMENT

LG&E and KU hereby incorporate the Baseline Congestion Management Process (Version 1.2), which is attached hereto.

~~ATTACHMENT Q~~

AGREEMENTS BETWEEN THE TRANSMISSION OWNER AND THE ITO AND THE RELIABILITY COORDINATOR

Independent Transmission Organization Agreement

Between

Louisville Gas and Electric Company/
Kentucky Utilities Company

And

TranServ International, Inc.

FINAL

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INDEPENDENT TRANSMISSION ORGANIZATION AGREEMENT

This Independent Transmission Organization ("ITO") Agreement (this "Agreement") is entered into on ~~August 29, 2011,~~September 1, 2017, between Louisville Gas and Electric Company and Kentucky Utilities Company, corporations organized pursuant to the laws of the Commonwealth of Kentucky (collectively, "Company"), and TranServ International, Inc., an entity organized pursuant to the laws of Delaware ("TranServ"). Company and TranServ may sometimes be individually referred to herein as a "Party" and collectively as the "Parties."

WHEREAS, Company owns, among other things, an integrated electric transmission system ("Transmission System"), over which open access transmission service is provided to customers in the Company~~'~~'s Balancing Authority Area (as that term is defined by the North American Electric Reliability Corporation ("NERC"));

WHEREAS, the Company has an Open Access Transmission Tariff ("OATT") on file with the Federal Energy Regulatory Commission ("FERC")

WHEREAS, Company~~ currently operates its Transmission System with certain services provided by Southwest Power Pool, Inc. ("SPP"); WHEREAS, Company'~~'s current contract with ~~SPP~~TranServ is scheduled to expire on August 31, ~~2012~~2017;

WHEREAS, Company desires that, upon expiration of the current contract~~ with SPP~~, TranServ will ~~assume certain duties with regard to Company's Transmission System~~continue its work under this Agreement, as detailed herein;

WHEREAS, Company remains the owner of its Transmission System and shall be the ultimate provider of transmission services to Eligible Customers (as defined in the OATT), including the sole authority to amend the OATT;

WHEREAS, TranServ: (i) is independent from Company; (ii) possesses the necessary competence and experience to perform the functions provided for hereunder; and (iii) is willing to perform such functions under the terms and conditions agreed upon by the Parties as set forth in this Agreement; and

WHEREAS, as part of Company~~'~~'s goal to maintain independence in the operation of its Transmission System in order to prevent any exercise of transmission market power, Company entered into a Reliability Coordinator Agreement (the "Reliability Coordinator Agreement") with the Tennessee Valley Authority, NERC-certified reliability coordinator (the "Reliability Coordinator"), pursuant to which the Reliability Coordinator provides to Company certain required reliability functions.

NOW THEREFORE, in consideration of the mutual promises contained herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties hereby agree as follows:

Section 1 - Services to be Provided; Standards of Performance

1.1 Services. TranServ shall perform, or cause to be performed, the services described in Appendix A hereto as well as any obligations expressly assigned to the ITO under the OATT ("ITO Services") during the Term in accordance with the terms and conditions of this Agreement, subject to modification pursuant to Section 1.4 hereto.

1.2 Coordination with Reliability Coordinator. In conjunction with its performance of ITO Services, TranServ shall coordinate and cooperate with the Reliability Coordinator in accordance with the terms of the OATT and all NERC and SERC Reliability Corporation ("SERC") requirements. TranServ shall provide to the Reliability Coordinator, subject to the terms and conditions of this Agreement, including TranServ~~'~~'s obligations with respect to Confidential Information in Section 10, any information that the Reliability Coordinator may reasonably request in order to carry out its functions under the Reliability Coordinator Agreement, which agreement is included in the OATT.

1.3 TranServ Performance; Compliance.

1.3.1 Performance. TranServ, TranServ Personnel and any TranServ Designee (as defined in Section 17.5) shall perform TranServ~~'~~'s obligations (including ITO Services) under this Agreement:

(a) in an independent, fair, and nondiscriminatory manner; and

(b) in accordance with:

(i) any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition ("Good Utility Practice"). Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 2 14(a)(4);

(ii) the terms and conditions of the OATT;

(iii) all applicable laws and the requirements of federal and state regulatory authorities, including the Kentucky Public Service Commission ("KPSC"), Department of Energy ("DOE"), FERC, NERC, SERC, and the North American Electric Standards Board ("NAESB") (collectively, "Regulatory Authorities"); and in fulfilling this requirement in this subsection (iii), TranServ will cooperate with all reasonable requests by Company for information, interviews with TranServ personnel, or other support that may be needed to investigate possible FERC, NERC or other compliance violations or prepare for or respond to compliance-related audits, self-certifications, and other inquiries by Regulatory Authorities (whether internal or external); and

(iv) any methodologies, processes, or procedures relating to

ITO Services which Company may develop and which Company determines are necessary or appropriate to ensure safe and reliable system operations and compliance with all applicable laws and the applicable requirements of Regulatory Authorities.

1.4 Changes to ITO Services. The Parties agree that all changes to ITO Services resulting from legal and regulatory developments, as well as Company requests, shall be assessed using a change order process. This process will include a written assessment of impacts to ITO Services consistent with Section 5 of Appendix A. Changes will be implemented only after mutual execution of a change document, which may be titled a Change Order or an Amendment. If the Parties are unable to agree on whether a change constitutes a “Minor Change,” or a “Major Change,” as those terms are used in Section 5 of Appendix A, such Dispute shall be resolved in accordance with Section 3.6.

Section 2 - Independence and Standards of Conduct

2.1 TranServ Personnel. All ITO Services shall be performed by staff members of TranServ (“TranServ Personnel”) or TranServ Designees. No TranServ Personnel or TranServ Designee shall also be employed by Company or any of its Affiliates (as defined in FERC’s regulations, 18 C.F.R. § 35.34(b)(3) (2011)). TranServ, TranServ Employees, and TranServ Designees shall (i) be Independent of and (ii) shall not discriminate against Company, any of its Affiliates, or any Tariff Participant. For purposes of this Agreement: (a) “Independent” shall mean that TranServ, TranServ Personnel, and any TranServ Designees are not subject to the control of Company, its Affiliates or any Tariff Participant, and have full decision-making authority to perform all ITO Services in accordance with the provisions of this Agreement. Any TranServ Personnel or TranServ Designee owning securities in Company, its Affiliates or any Tariff Participant shall divest such securities within six (6) months of first being assigned to perform such ITO Services, provided that nothing in this Section 2.1 shall be interpreted or construed to preclude any such TranServ Personnel or TranServ Designee from indirectly owning securities issued by Company, its Affiliates or any Tariff Participant through a mutual fund or similar arrangement (other than a fund or arrangement specifically targeted toward the electric industry or the electric utility industry or any segment thereof) under which the TranServ Personnel or the TranServ Designee does not control the purchase or sale of such securities. Participation by any TranServ Personnel or TranServ Designee in a pension plan of Company, its Affiliates or any Tariff Participant shall not be deemed to be a direct financial interest if the plan is a defined-benefit plan that does not involve the TranServ Personnel’s or TranServ Designee’s ownership of the securities; and (b) “Tariff Participant” shall mean Company Transmission System customers, interconnection customers, wholesale customers, affected transmission providers, any Market Participant (as defined in FERC’s regulations, 18 C.F.R. § 35.34(b)(2) (2011)) and similarly qualified third parties within the Company Balancing Authority Area. For the avoidance of doubt, Company shall have no veto authority over the selection of TranServ Personnel or TranServ Personnel matters, including TranServ’s appointment of a TranServ Project Manager (as provided in Section 8.2)~~.~~ except that the Company and TranServ hereby agree that TranServ shall be prohibited from hiring current or former Company employees until at least one (1) year subsequent to the Company employee’s separation from Company. Likewise, Company is prohibited from hiring current or former TranServ employees until one (1) year subsequent to the TranServ employee’s separation from TranServ.

2.2 Standards of Conduct Treatment. All TranServ Personnel and TranServ Designees performing work under this Contract shall be treated, for purposes of the FERC~~’~~’s Standards of Conduct (18 C.F.R. Part 358 ~~(2011)~~), as transmission function employees. All restrictions relating to information sharing and other relationships between marketing function employees and transmission function employees, as those terms are defined in the Standards of Conduct, including the non-discrimination requirements contained therein, shall apply to TranServ Personnel and TranServ Designees~~. –~~ performing work under this Contract, or likely to become privy to transmission function information. Said TranServ Personnel and TranServ Designees shall participate in any Standards of Conduct training that the Company may request for compliance purposes. TranServ shall provide prompt notice of new TranServ Personnel or TranServ Designees to Company to assure new persons are trained within the first thirty (30) days of their employment with TranServ.

Section 3 - Compensation; Billing and Payment; Performance Review

3.1 Compensation for Services. Company shall pay to TranServ an annual fee for performance of the ITO Services (“Annual Fee”). The Annual Fee ~~shall be $2,495,938~~(subject to increases or decreases in accordance with Section 5 of Appendix A) shall be $2,479,543.56 for the first Contract Year~~,~~ and shall escalate by ~~two~~one and five/tenths percent (~~2.5~~1.5%) of the prior year~~’~~’s Annual Fee for each Contract Year thereafter.

3.2 Out-of-Pocket Costs. Company shall reimburse TranServ for actual out-of-pocket third party costs and expenses, without markup, for (a) regulatory legal support that is reasonably allocable to TranServ~~’~~’s performance of ITO Services, provided that in no event shall Company reimburse TranServ for legal fees associated with any actual or potential Dispute under this Agreement, (b) travel and lodging that are reasonably allocable to TranServ~~’~~’s performance of ITO Services and (c) setting up regular stakeholder meetings (collectively, (a), (b) and (c) are “Out-of-Pocket Costs”); provided, however, that all Out-of-Pocket Costs subject to reimbursement under this Section 3.2 must be reviewed and approved by Company prior to TranServ incurring such expense.

3.3 ~~Transmission Study Revenue. During the Term, TranServ expects that it will receive $225,000 USD annually in System Impact Study (“SIS”) and Interconnection Feasibility Study (as performed under the generator interconnection processes under the OATT, “IFS”) (collectively, SIS and IFS are “Transmission Studies”) revenue from customers requesting service under the OATT. If TranServ fails to receive this amount during any Contract Year, then the Company shall pay TranServ an annual “true-up” payment equal to the difference between the amount TranServ did receive in Transmission Studies revenue and $225,000 during the applicable Contract Year (“Transmission Study True Up Payment”); provided that TranServ shall be obligated to refund to Company any Transmission Study True Up Payment to the extent TranServ subsequently collects revenue from customers thereafter for Transmission Studies performed in the previous Contract Year; and provided further, that Company shall not be obligated to pay any Transmission Study True Up Payment to the extent that TranServ’s inability to receive the full $225,000 USD during any Contract Year is due to either (a) TranServ’s failure to bill customers for Transmission Studies, or (b) a customer’s failure to pay for Transmission Studies TranServ has performed. Additionally, to the extent that TranServ’s failure to perform System Impact Studies within the timeframe required under Sections 19.3 or 32.3 of the OATT (as applicable) results in Company being subject to penalties pursuant to Sections 19.10 or 32.5 of the OATT (as applicable), when such penalties are assessed such amount shall be deducted~~

~~from the Transmission Study True-Up payment or any other payments due to TranServ under this Agreement, in partial satisfaction of TranServ's obligation to indemnify Company pursuant to Section 7.3; provided that in no event shall Company withhold a Transmission Study True Up Payment or other payment due to TranServ while a possible penalty determination is pending; and provided further, that the limitations included in Section 7.6 shall apply. 3.4~~ Payment.

3.4.1 Monthly Payment. TranServ shall deliver to Company monthly invoices by regular mail, facsimile, electronic mail or such other means as the Parties agree. Such invoices shall set forth (i) one-twelfth (1/12) of the Annual Fee for each month in advance, and (ii) any Out-of-Pocket costs incurred during the previous month, provided however, that travel expenses occurring on the last three (3) days of each month may be carried over to future invoices for ease of administration. Company shall make payment of the amount invoiced by wire transfer in immediately available funds to an account specified by TranServ not later than the thirtieth (30^{th}) day after receipt of the invoice, unless such day is not a business day, in which case on the next business day. All such payments shall be deemed made when said wire transfer is received by TranServ. Overdue payments shall accrue interest calculated at the FERC interest rate as defined in 18 C.F.R. §35.19a(2)(iii)(A) (2011) ("FERC Interest Rate").

~~3.5~~3.4 Annual Review~~ and True Up Payments~~.

~~3.5.1~~3.4.1 Annual Review. Commencing at the end of ~~the second~~each Contract Year, no later than sixty (60) days after the end of each Contract Year, TranServ shall determine and deliver to Company a calculation of TranServ~~'~~'s actual labor in providing ITO Services for the preceding Contract Year ("Annual Labor"). The Annual Labor calculation shall detail the job title and number of full-time employees assigned to ITO Services, and the number of hours spent in performing ITO Services. The Annual Labor shall also include the hours for any tasks which TranServ outsourced to TranServ Designees.

~~3.5.2 Transmission Study True Up Payment Calculation and Payment. No later than sixty (60) days after the end of each Contract Year, TranServ shall determine and deliver to Company a calculation of the Transmission Study True Up Payment, if any. Such calculation shall include the aggregate amount of Transmission Study revenues invoiced by TranServ for the applicable year. No later than ten (10) days after the calculation the Transmission Study True Up Payment, TranServ shall send an invoice to the Company reflecting the sum of the Transmission Study True Up Payment. Company shall make payment of the amount invoiced by wire transfer in immediately available funds to an account specified by TranServ not later than the thirtieth (30th) day after receipt of the invoice, unless such day is not a business day, in which case on the next business day. All such payments shall be deemed made when said wire transfer is received by TranServ. Overdue payments shall accrue interest calculated at FERC Interest Rate.~~

~~3.6~~3.5 Compensation Disputes. Notwithstanding the Dispute resolution provisions in Section 8.3, for any Disputes concerning compensation under this Section 3, Company shall timely file notice of such Dispute with FERC and request that FERC resolve such Dispute. TranServ retains the authority to file notice with FERC of any such Dispute if it so desires. If either Party in good faith disputes any invoice submitted by the other Party pursuant to this Agreement, then the disputing Party (i) shall timely pay the other Party the entire invoiced amount and (ii) shall furnish the other Party with a written explanation specifying the amount of and the basis for the Dispute. Within twenty (20) days after resolution of such Dispute, the Party owing money shall pay the other Party the amount owed, if any, together with interest calculated at the FERC Interest Rate.

Section 4 - Term and Termination

4.1 Term. The initial term of this Agreement shall begin on ~~the later of (a) September 1, 2012 or (b) such date approved by applicable Regulatory Authorities for TranServ to begin performing ITO Services (either (a) or (b) being the~~ September 1, 2017 ("Commencement Date"), and shall continue for ~~three~~five (~~3~~5) years thereafter ("Initial Term"). At the conclusion of the Initial Term, this Agreement shall automatically extend for ~~two (2)~~ successive one (1) year terms (each a "Subsequent Term"), unless terminated by either Party in accordance with the terms of this Agreement. Three hundred and sixty (360) days prior to the conclusion of the Initial Term either Party may notify the other, in writing, of a desire to amend terms or pricing of this Agreement for the Subsequent Terms. If such amendment is not agreed upon by both parties 180 days prior to the beginning of the first Subsequent Term, the Amendment shall not automatically extend and will terminate on the later of i) the conclusion of the Initial Term, as defined above, or ii) receipt of the regulatory approvals required under Section 4.5. The Initial Term or any Subsequent Terms are each referred to herein as a "Term." For the purposes of this Agreement, a "Contract Year" shall begin on the Commencement Date or anniversary thereof and conclude twelve (12) months thereafter.

4.2 Termination by Either Party. This Agreement may be terminated by either Party at the end of a Term upon prior one hundred eighty (180) days written notice to the other Party, which termination shall be effective upon the later of (i) one hundred eighty (180) days after the date of such written notice, or (ii) receipt of the regulatory approvals required under Section ~~4.6.~~4.5.

4.3 ~~Termination at End of Term. Unless previously terminated in accordance with this Section 4, and subject to Section 4.6, this Agreement shall terminate on the fifth (5th) anniversary of the Commencement Date.4.4~~ Immediate Termination.

~~4.4.1~~4.3.1 Termination for Cause. Subject to Section ~~4.6,~~4.5, either Party may terminate this Agreement upon prior written notice thereof to the other Party if:

(a) Material Failure or Default. The other Party fails, in any material respect, to comply with, observe or perform, or defaults, in any material respect, in the performance of the terms and conditions of this Agreement, and such failure or default remains uncured for thirty (30) days after written notice thereof, provided that such failure or default is susceptible to cure and the other Party is exercising reasonable diligence to cure such failure or default;

(b) Pattern of Failure. It determines, in its reasonable discretion, that there has been a pattern of failure by the other Party to comply with the standards of performance set forth in Section 1.3.1, whether or not such failure is material;

(c) Gross Negligence, Willful Misconduct or Fraud. The other Party commits gross negligence, willful misconduct or fraud in the performance of its obligations under this Agreement;

(d) Material Misrepresentation. Any representation made by the other Party hereunder shall be false or incorrect in any material respect when made and such misrepresentation is not cured within thirty (30) days of such discovery or written notice thereof, or is incapable of cure;

(e) Bankruptcy. The other Party: (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it; (ii) makes an assignment or any general arrangement for the benefit of creditors; (iii) otherwise becomes bankrupt or insolvent (however evidenced); (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets; or (v) is generally unable to pay its debts as they fall due; or

(f) Dissolution. The other Party dissolves or is dissolved or its legal existence is otherwise terminated.

~~4.4.2~~4.3.2 Immediate Termination Not For Cause. Subject to Section ~~4.6,~~4.5, Company may terminate this Agreement upon thirty (30) days prior written notice thereof to TranServ if:

(a) Failure to Negotiate Amendment. The Parties are unsuccessful in negotiating an amendment or amendments to this Agreement pursuant to Section 17.9;

(b) Regulatory Changes/Modifications. A Regulatory Authority makes any material changes, modifications, additions, or deletions to this Agreement, unless both Parties agree to such changes, modifications, additions, or deletions;

(c) Failure to Receive Regulatory Approval. Prior to the Commencement Date, FERC rejects this Agreement or Company~~'~~'s selection of TranServ as the ITO;

(d) RTO. ~~A Regulatory Authority requires~~ Company ~~to join~~joins a regional transmission organization ("RTO"); or

(e) Extended Force Majeure. A Party is excused because of Force Majeure (as defined in Section 11) for more than thirty (30) days from performing any of its material obligations under this Agreement.

~~4.5~~4.4 Termination for Lack of Independence. Subject to Section ~~4.6,~~4.5, Company may terminate this Agreement upon prior written notice thereof to TranServ if FERC or the KPSC issues a final order that declares that TranServ lacks independence from Company and TranServ cannot obtain independence in a reasonable manner or time period.

~~4.6~~4.5 Regulatory Approval. No termination of this Agreement shall be effective until approved by FERC and the KPSC. Notice of termination provided pursuant to Sections ~~4.4~~4.3 and ~~4.5~~4.4 shall become effective immediately upon approval by FERC and the KPSC.

~~4.7~~4.6 Return of Materials. Upon any termination of this Agreement TranServ shall timely and in an orderly manner turn over to Company all materials that were prepared or developed pursuant to this Agreement prior to termination, and return or destroy, at the option of Company, all Data and other information supplied by Company to TranServ or created by TranServ on behalf of Company.

~~4.8~~4.7 Survival. All provisions of this Agreement which are by their nature or terms intended to survive the termination of this Agreement, including the obligations set forth in Section 7 and Section 10, shall survive termination of this Agreement.

~~4.9~~4.8 Compensation for Early Termination.

~~4.9.1~~4.8.1 If Company terminates this Agreement before the end of a Term pursuant to Section ~~4.4.2~~4.3.2 (a), (b), (d) or (e), then Company shall pay to TranServ the Annual Fee(s) through the longer of the end of the ~~then-current Term~~Contract Year or for six (6) months subsequent to the date of termination, which fees shall be accelerated hereunder for this purpose, plus any unpaid Out-of-Pocket Costs that TranServ has incurred through the date of any such termination. In the event that this Section ~~4.9.1~~4.8.1 should trigger an acceleration of Annual Fee(s) that would otherwise span multiple years, such fees paid by Company to TranServ shall not include any escalation of ~~two~~one and five/tenths percent (~~2.5~~1.5%) as described in Section 3.1 that had not yet been previously applied to the Annual Fee(s).

~~4.9.2~~4.8.2 If Company terminates this agreement before the end of the Term, and such termination is for cause pursuant to Section ~~4.4.1,~~4.3.1, then Company shall only be liable for TranServ~~'~~'s Out-of-Pocket Costs incurred pursuant to contracts which extend beyond any early termination date.

~~4.10~~4.9 Post-Termination Services. Commencing on the date that any termination becomes effective ("Termination Date") and continuing for up to one hundred eighty (180) days thereafter, TranServ shall (a) provide ITO Services (and any replacements thereof or substitutions therefor), to the extent Company requests such ITO Services to be performed, and (b) cooperate with Company in the transfer of ITO Services (collectively, the "Post-Termination Services") as such services are authorized under a separate agreement between the Parties. TranServ shall, upon Company~~'~~'s request, provide the Post-Termination Services at a cost to be negotiated and mutually agreed to at that time. The quality and level of performance of ITO Services by TranServ shall not diminish. After the expiration of the Post-Termination Services, TranServ shall answer questions from Company regarding ITO Services on an "as needed" basis at TranServ~~'~~'s then-standard billing rates.

4.10 Termination for Guarantee Termination. A guaranty with Open Access Technology International, Inc., in favor of Company and with TranServ as a counterparty was executed (November 29, 2016) (hereinafter "the Guaranty"). Subject to Section 4.5, Company may terminate this Agreement if the Guaranty is terminated and TranServ does not provide a replacement Guaranty determined, by Company, to be satisfactory.

Section 5 - Data Management and Intellectual Property

5.1 Supply of Data. During the Term, Company shall supply to TranServ, and/or grant TranServ access to all Data that TranServ requests and that TranServ believes is necessary to perform its duties and obligations under this Agreement, including ITO Services. The Parties shall agree upon the initial format and manner in which such Data shall be provided. For purposes of this Agreement, “Data” means all information, text, drawings, diagrams, models, images or sounds which are embodied in any electronic or tangible medium and which (a) are supplied or in respect of which access is granted to TranServ by Company under this Agreement, which shall be Company~~’~~’s Data, (b) are prepared, stored or transmitted by TranServ solely on behalf of Company, which shall be Company~~’~~’s Data; or (c) are compiled by TranServ by aggregating Data owned by Company and Data owned by third parties, which shall be TranServ~~’~~’s Data.

5.2 Property of Each Party. Each Party acknowledges that the other Party~~’~~’s Data and the other Party~~’~~’s software, base data models and operating procedures for software or base data models (“Processes”) are the property of such other Party and agrees that it will do nothing inconsistent with such ownership, including preserving all intellectual property and/or proprietary rights in such other Party~~’~~’s Data and Processes as provided in Section 6.

5.3 Data Integrity. Each Party shall reasonably assist the other Party in establishing measures to preserve the integrity and prevent any corruption or loss of Data, and the Parties shall reasonably assist each other in the recovery of any corrupted or lost Data. Each Party shall reasonably retain and preserve any of the other Party~~’~~’s Essential Data that are supplied to it during the Term. “Essential Data” means any Data that is reasonably required to perform ITO Services under this Agreement and that must be retained and preserved according to any applicable law, regulation, reliability criteria, or Good Utility Practice. Each Party shall exercise commercially reasonable efforts to preserve the integrity of the other Party~~’~~’s Data that are supplied to it during the Term, in order to prevent any corruption or loss of the other Party~~’~~’s Data.

5.4 Confidentiality. Each Party~~’~~’s Data shall be treated as Confidential Information in accordance with the provisions of Section 10.

Section 6 - Intellectual Property.

6.1 Ownership. All inventions, discoveries, processes, methods, designs, drawings, blueprints, information, ~~software,~~ works of authorship, or the like, whether or not patentable or copyrightable (collectively, “Intellectual Property”), which TranServ first conceives, develops, or begins to develop, either alone or in conjunction with Company or others, with respect to ITO Services under this Agreement, shall be jointly owned by Company and TranServ, and each party shall have the right to use such intellectual property unless specifically otherwise specified on a change document hereunder.

6.2 Royalties and License Fees. Unless the Parties otherwise agree in writing, TranServ shall procure and pay all royalties and license fees which may be payable on account of ITO Services or any part thereof. In case any part of ITO Services is held in any suit to constitute infringement and its use is enjoined, TranServ within a reasonable time shall, at the election of Company and as Company's exclusive remedy hereunder, either (a) secure for Company the perpetual right to continue the use of such part of ITO Services by procuring for Company a royalty-free license or such other permission as will enable TranServ to secure the suspension of any injunction, or (b) replace at TranServ's own expense such part of ITO Services with a non-infringing part or modify it so that it becomes non-infringing (in either case with changes in functionality that are acceptable to Company).

Section 7 - Indemnification and Limitation of Liability

7.1 Company Indemnification. Subject to the limitations specified in Section 7.6, Company shall indemnify, release, defend, reimburse and hold harmless TranServ and its directors, officers, employees, principals, representatives and agents (collectively, the "TranServ Indemnified Parties") from and against any and all third party claims (including claims of bodily injury or death of any person or damage to real and/or tangible personal property), demands, liabilities, losses, causes of action, awards, fines, penalties, litigation, administrative proceedings and investigations, costs and expenses, and attorney fees, (each, an "Indemnifiable Loss") asserted against or incurred by any of the TranServ Indemnified Parties arising out of, resulting from or based upon TranServ performing its obligations pursuant to this Agreement, provided, however, that in no event shall Company be obligated to indemnify, release, defend, reimburse or hold harmless the TranServ Indemnified Parties from and against any Indemnified Loss which is caused by the negligence, the gross negligence or willful misconduct of any TranServ Indemnified Party.

7.2 TranServ Indemnification. Subject to the limitations specified in Section 7.6, TranServ shall indemnify, release, defend, reimburse and hold harmless Company and its directors, officers, employees, principals, representatives and agents (collectively, the "Company Indemnified Parties") from and against any and all Indemnifiable Losses asserted against or incurred by any of the Company Indemnified Parties arising out of, resulting from or based upon TranServ's or a TranServ Designee's negligence, gross negligence, or willful misconduct, provided, however, that in no event shall TranServ be obligated to indemnify, release, defend, reimburse or hold harmless any Company Indemnified Parties from and against any Indemnified Loss which is caused by the negligence, gross negligence or willful misconduct of any Company Indemnified Party.

7.3 Regulatory Indemnification. Subject to the limitations specified in Section 7.6, TranServ shall indemnify, release, defend, reimburse and hold harmless any Company Indemnified Parties from and against all regulatory penalties and sanctions (including penalties or sanctions levied by a Regulatory Authority) arising out of, resulting from or based upon TranServ breach of this Agreement, specifically including Section 1.3.1 hereto, provided, however, that in no event shall TranServ be obligated to indemnify, release, defend, reimburse or hold harmless any Company Indemnified Parties from and against any penalty or sanction which is caused by the gross negligence or willful misconduct of any Company Indemnified Party.

7.4 Cooperation Regarding Claims. If an Indemnified Party (which for purposes of this Section 7.4 shall mean an TranServ Indemnified Party or a Company Indemnified Party) receives notice or has knowledge of any Indemnifiable Loss that may result in a claim for indemnification by such Indemnified Party against an Indemnifying Party (which for purposes of this Section 7.4

shall mean Company or TranServ) pursuant to this Section 7, such Indemnified Party shall as promptly as possible give the Indemnifying Party written notice of such Indemnifiable Loss, including a reasonably detailed description of the facts and circumstances relating to such Indemnifiable Loss, a complete copy of all notices, pleadings and other papers related thereto, and in reasonable detail the basis for its claim for indemnification with respect thereto. Failure to promptly give such written notice or to provide such information and documents shall not relieve the Indemnifying Party from the obligation hereunder to respond to or defend the Indemnified Party against such Indemnifiable Loss unless and only to the extent such failure shall materially diminish the ability of the Indemnifying Party to respond to or to defend the Indemnified Party against such Indemnifiable Loss. Except for indemnification for penalties and sanctions under Section 7.3, the Indemnifying Party, upon its acknowledgment in writing of its obligation to indemnify the Indemnified Party in accordance with this Section 7, shall be entitled to assume the defense or to represent the interest of the Indemnified Party with respect to such Indemnifiable Loss, which shall include the right to select and direct legal counsel and other consultants, appear in proceedings on behalf of such Indemnified Party and to propose, accept or reject offers of settlement, all at its sole cost. If and to the extent that the defense or settlement of any Indemnifiable Loss is reasonably likely to involve injunctive, equitable or prospective relief or materially and adversely affect the Indemnified Party’’s business or operations other than as a result of money damages or other money payments assumed by the Indemnifying Party, then such defense or settlement will be subject to the reasonable approval of the Indemnified Party. Nothing herein shall prevent an Indemnified Party from retaining its own legal counsel and other consultants and participating in its own defense at its own cost and expense.

7.5 Release and Indemnification Regarding Liens. TranServ hereby releases and/or waives for itself and its successors in interest, and for all TranServ Designees and their successors in interest, any and all claims or right of mechanics or any other type of lien to assert and/or file upon Company’’s or any other party’’s property or any part thereof as a result of performing ITO Services. TranServ shall execute and deliver to Company such documents as may be required by applicable laws (*i.e.*, partial and/or final waivers of liens and/or affidavits of indemnification) to make this release effective and shall give all required notices to TranServ Designees with respect to ensuring the effectiveness of the foregoing releases against those parties. TranServ shall secure the removal of any lien that TranServ has agreed to release in this Section 7.5 within five (5) working days of receipt of written notice from Company to remove such lien. If not timely removed, Company may remove the lien and charge all costs and expenses including legal fees (for inside and/or outside legal counsel) to TranServ including, without limitation, the costs of bonding off such lien. Company, in its sole discretion, expressly reserves the right to off-set and/or retain any reasonable amount due to TranServ from payment of any one or more of TranServ’’s invoices upon Company having actual knowledge of any threatened and/or filed liens and/or encumbrances that may be asserted and/or filed by any TranServ Designee and/or third party with respect to the ITO Services, with final payment being made by Company only upon verification that such threatened and/or filed liens and/or encumbrances have been irrevocably satisfied, settled, resolved and/or released (as applicable), and/or that any known payment disputes concerning the ITO Services involving TranServ and any TranServ Designees have been resolved so that no actions, liens and/or encumbrances of any kind or nature will be filed against Company and/or Company’’s property.

7.6 Limitation of Liability. Other than as provided in Section 7.3, neither Party shall be liable to the other for any special, punitive, or consequential damages arising out of ITO Services, even if advised of the possibility of such damages. Company agrees that ITO Services are not consumer goods for purposes of international, U.S. Federal or U.S. state warranty laws. Indemnification pursuant to Sections 7.1, 7.2, and 7.3, as well as any direct damages to Company arising out of a material breach of this Agreement shall be limited in the aggregate to the total amount of fees actually paid by Company to TranServ under this Agreement through the date that any penalty or judgment is assessed.

Section 8 - Contract Managers; Dispute Resolution

8.1 Company Contract Manager. Company shall appoint an individual (the "Company Contract Manager") who shall serve as the primary Company representative under this Agreement. The Company Contract Manager shall (a) have overall responsibility for managing and coordinating the performance of Company's obligations under this Agreement, and (b) be authorized to act for and on behalf of Company with respect to all matters relating to this Agreement. Notwithstanding the foregoing, the Company Contract Manager may, upon written notice to TranServ, delegate such of his or her responsibilities to other Company employees, as the Company Contract Manager deems appropriate.

8.2 TranServ Project Manager. TranServ shall appoint, among TranServ Personnel, an individual (the "TranServ Project Manager") who shall serve as the primary TranServ representative under this Agreement. The TranServ Project Manager shall have overall responsibility for managing and coordinating the performance of TranServ obligations under this Agreement. Notwithstanding the foregoing, the TranServ Project Manager may, upon written notice to Company, delegate such of his or her responsibilities to other TranServ Personnel, as the TranServ Project Manager deems appropriate.

8.3 Resolution of Disputes. Any dispute, claim or controversy between the Parties arising out of or relating to this Agreement (each, a "Dispute") shall be resolved in accordance with the procedures set forth in this Section 8.3; provided, however, that this Section 8.3 shall not apply to Disputes arising from or relating to (a) the amount of compensation to be paid by Company pursuant to Section 3.1, which shall be resolved pursuant to Section 3.6, (b) confidentiality or intellectual property rights, in which case either Party shall be free to seek available legal or equitable remedies, or (c) alleged violations of the OATT, in which case either Party shall be free to bring the Dispute to FERC.

8.3.1 Notice of Dispute. Each Party shall provide written notice to the other party of any Dispute, including a description of the nature of the Dispute.

8.3.2 Dispute Resolution by Contract Managers. Any Dispute shall first be referred to the Company Contract Manager and TranServ Project Manager, who shall negotiate in good faith to resolve the Dispute.

8.3.3 Dispute Resolution by Executive Management Representatives. If the Dispute is not resolved within fifteen (15) calendar days of being referred to the Company Contract Manager and the TranServ Project Manager pursuant to Section 8.3.2, then each Party shall have five (5) calendar days to appoint an executive management representative who shall negotiate in good faith to resolve the Dispute.

8.3.4 Binding Arbitration. If the Dispute is not resolved within ten (10) calendar days of being referred to executive management representatives, and the amount in dispute or potential damages exceeds $250,000 USD, the Parties shall proceed in good faith to submit immediately the matter to binding arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("AAA") as they may be amended from time to time (the "Arbitration Rules") subject to the following conditions:

(a) The Parties shall give due consideration to using the Expedited Procedures under the Arbitration Rules in any case in which no disclosed claim or counterclaim exceeds $75,000, exclusive of interest and arbitration fees and costs.

(b) The Parties agree that three arbitrators will be used. Each Party will directly appoint one arbitrator of its choosing from a list of members from the National Roster (as that term is used in the Arbitration Rules) provided by the AAA pursuant to R-12, within ten (10) Days after receipt of such names. The two arbitrators so appointed shall select a third arbitrator from the National Roster to serve as chairperson.

(c) "Baseball" arbitration (in which each Party presents a proposed award or resolution and the actual award must be one of the two submitted), or close variants thereof, shall not be used.

(d) The arbitrators have no authority to appoint or retain expert witnesses for any purpose unless agreed to by the Parties.

(e) All arbitration fees and costs shall be borne equally, regardless of which Party prevails.

(f) Each Party shall bear its own costs of legal representation and witness expenses, unless the arbitrator(s) determines that one Party should bear some or all of the costs of legal representation and witness expenses of the other Party.

(g) The Parties waive any right of appeal or recourse to any court except to compel arbitration, to compel the appointment of arbitrators, to stay judicial proceedings pending arbitration, for an injunction pending determination by the arbitrators, for disqualification of arbitrators, for aid in furtherance of arbitration, to confirm the award, to enforce any judgment confirming the award, or in circumstances of fraud or failure to disclose information or documents required by the arbitrators.

(h) The decision or award of a majority of the arbitrators shall govern. The decision or award of the arbitrators shall be final and binding upon the Parties to the same extent and to the same degree as if the matter had been adjudicated by a court of competent jurisdiction and shall be enforceable under the Federal Arbitration Act and applicable states~~'~~' laws.

8.3.5 Rights and Remedies. If the Dispute is not resolved within ten (10) calendar days of being referred to executive management representatives, and the amount in dispute or potential damages does not exceed $250,000 USD, each Party is free to pursue any rights or remedies it may have at law or equity.

8.4 Rights Under FPA Unaffected. Except as provided in Section 17.2 relating to the variation or amendment of this Agreement, nothing in this Agreement is intended to limit or abridge any rights that Company may have to file or make application before FERC under Section 205 of the Federal Power Act to revise any rates, terms or conditions of the OATT.

8.5 Statute of Limitations; Continued Performance. The Parties agree to waive the applicable statute of limitations during the period of time that the Parties are seeking to resolve a Dispute pursuant to Section 8.3, and the statute of limitations shall be tolled for such period. The Parties shall continue to perform their obligations under this Agreement during the resolution of a Dispute.

Section 9 - Insurance

9.1 TranServ'’s Insurance Obligation. During the Term, TranServ shall provide and maintain, and shall require TranServ Designees to provide and maintain, the following insurance (and, except with regard to Workers'’ Compensation, naming Company as additional insured and waiving rights of subrogation against Company and Company'’s insurance carrier(s)), and TranServ shall submit evidence of such coverage(s) of TranServ and any TranServ Designees to Company prior to the start of ITO Services. Furthermore, TranServ shall notify Company, prior to the commencement of ITO Services, of any threatened, pending and/or paid off claims to third parties, individually or in the aggregate, which otherwise affects the availability of the limits of such coverage(s) inuring to the benefit of Company as hereinafter specified:

9.1.1 Workers'’ Compensation and Employer'’s Liability Policy, which shall include provisions required by applicable law in the jurisdiction of location of workers.

9.1.2 Employer'’s Liability (Coverage B) with limits of One Million Dollars ($1,000,000) Bodily Injury by Accident, each Accident, $1,000,000 Bodily Injury by Disease, each Employee, and including:

(a) a thirty (30) day cancellation clause; and

(b) broad form all states endorsement.

9.1.3 Commercial General Liability Policy, which shall have minimum limits of One Million Dollars ($1,000,000) each occurrence; One Million Dollars ($1,000,000) Products/Completed Operations Aggregate each occurrence; One Million Dollars ($1,000,000) Personal and Advertising Injury each occurrence, in all cases subject to Two Million Dollars ($2,000,000) in the General Aggregate for all such claims, and including:

(a) a thirty (30) day cancellation clause;

(b) Blanket Written Contractual Liability to the extent covered by the policy against liability assumed by TranServ under this Agreement; and

(c) Broad Form Property Damage.

9.1.4 Commercial Automobile Liability Insurance covering the use of all owned, non-owned, and hired automobiles, with a bodily injury, including death, and property damage combined single minimum limit of One Million Dollars ($1,000,000) each occurrence with respect to TranServ’s vehicles assigned to or used in performance of ITO Services under this Agreement.

9.1.5 Umbrella/Excess Liability Insurance with minimum limits of Two Million Dollars ($2,000,000) per occurrence; Two Million Dollars ($2,000,000) aggregate, to apply to employer’s liability, commercial general liability, and automobile liability.

9.1.6 To the extent applicable, if engineering or other professional services will be separately provided by TranServ as specified in Appendix A, then Professional Liability Insurance with limits of Three Million Dollars ($3,000,000) per occurrence and Three Million Dollars ($3,000,000) in the aggregate, which insurance shall be either on an occurrence basis or on a claims made basis (with a retroactive date satisfactory to Company).

9.2 Quality of Insurance Coverage. The above policies to be provided by TranServ shall be written by insurance companies which are both licensed to do business in the state where ITO Services will be performed and either satisfactory to Company or having a Best Rating of not less than “A-”. These policies shall not be materially changed or canceled except with thirty (30) days written notice to Company from TranServ and the insurance carrier. Evidence of coverage, notification of cancellation or other changes shall be mailed to: Attention: Manager, Supply Chain, LG&E and KU Services Company, P.O. Box 32020, Louisville, Kentucky 40232.

9.3 Implication of Insurance. Company reserves the right to request and receive a summary of coverage of any of the above policies or endorsements; however, Company shall not be obligated to review any of TranServ’s certificates of insurance, insurance policies, or endorsements, or to advise TranServ of any deficiencies in such documents. Any receipt of such documents or their review by Company shall not relieve TranServ from or be deemed a waiver of Company’s rights to insist on strict fulfillment of TranServ’s obligations under this Agreement.

9.4 Other Notices. TranServ shall provide written notice of any accidents or claims in connection with ITO Services or this Agreement to Company’s Manager, Risk Management at LG&E and KU Services Company, P.O. Box 32030, Louisville, Kentucky 40232.

Section 10 - Confidentiality

10.1 Definition of Confidential Information. For purposes of this Agreement, “Confidential Information” shall mean, in respect of each Party, all information and documentation of such Party, whether disclosed to or accessed by the other Party in connection with this Agreement and which is identified as Confidential Information, or which otherwise would be treated as confidential by the recipient, including confidential information provided by third-parties; provided, however, that the term “Confidential Information” shall not include information that: (a) is independently developed by the recipient, as demonstrated by the recipient’s written records, without violating the disclosing Party’s proprietary rights; (b) is or becomes publicly known (other than through unauthorized disclosure); (c) is disclosed by the owner of such information to a third party free of any obligation of confidentiality; (d) is already known by the recipient at the time of disclosure, as demonstrated by the recipient’s written records, and the recipient has no obligation of confidentiality other than pursuant to this Agreement or any confidentiality agreements between the Parties entered into before the Commencement Date; or (e) is rightfully received by a Party free of any obligation of confidentiality.

10.2 Protection of Confidential Information. All Confidential Information shall be held in confidence by the recipient to the same extent and in at least the same manner as the recipient protects its own Confidential Information, and such Confidential Information shall be used only for purposes of performing obligations under this Agreement. Except as otherwise provided in Section 10.3, neither Party shall disclose, publish, release, transfer or otherwise make available Confidential Information of, or obtained from, the other Party in any form to, or for the use or benefit of, any person or entity without the owner of such information~~’~~’s prior written consent. Each Party shall be permitted to disclose relevant aspects of the other Party~~’~~’s Confidential Information to its officers, directors, agents, professional advisors, contractors, subcontractors (including TranServ Designees) and employees and to the officers, directors, agents, professional advisors, contractors, subcontractors and employees of its Affiliates (collectively, “Representatives”), to the extent that such disclosure is reasonably necessary for the performance of its duties and obligations or the determination, preservation or exercise of its rights and remedies under this Agreement; provided, however, that the recipient shall take all reasonable measures to ensure that Confidential Information is not disclosed or duplicated in contravention of the provisions of this Agreement by such officers, directors, agents, professional advisors, contractors, subcontractors and employees. Recipient agrees to be liable for the wrongful actions of its Representatives under this Section 10.2. The obligations in this Section 10 shall not restrict any disclosure pursuant to any Regulatory Authority if such release is necessary to comply with valid laws, governmental regulations or final orders of regulatory bodies or courts; provided that, other than in respect of disclosures pursuant to Section 10.3, the recipient shall give prompt written notice to the disclosing Party in reasonable time to exercise whatever legal rights the disclosing Party may have to prevent or limit such disclosure. Further, the recipient shall cooperate with the disclosing Party in preventing or limiting such disclosure.

10.3 Regulatory Requests for Confidential Information. Notwithstanding anything in this Section 10 to the contrary, if a Regulatory Authority or its staff, during the course of an investigation or otherwise, requests Confidential Information from TranServ, TranServ shall provide the requested Confidential Information to the requesting Regulatory Authority or its staff within the time provided for in the request for information. In providing the Confidential Information to a Regulatory Authority or its staff, TranServ shall, consistent with 18 C.F.R. § 388.112 (2011) or any other applicable confidentiality regulation, request that the Confidential Information be treated as confidential and non-public by the Regulatory Authority and its staff and that the information be withheld from public disclosure. TranServ shall notify Company when it is notified by the Regulatory Authority or its staff that a request for public disclosure of, or decision to publicly disclose, Confidential Information has been received, at which time either TranServ or Company may respond before such Confidential Information is made public, pursuant to 18 C.F.R. § 388.112 or the applicable confidentiality regulation.

Section 11 - Force Majeure.

11.1 Force Majeure. Neither Party shall be liable to the other Party for any failure or delay of performance hereunder due to an event which (i) is not reasonably foreseeable or within the reasonable control of the Party claiming Force Majeure (the “Claiming Party”) or any Person over which the Claiming Party has control, (ii) was not caused by the acts, omissions, negligence, fault or delays of the Claiming Party or any person over whom the Claiming Party has control, (iii) is not an act, event or condition the risks or consequences of which the Claiming Party has expressly agreed to assume pursuant to this Agreement, and (iv) by the prompt exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided (collectively, (i) - (iv) are "Force Majeure"). Force Majeure shall include: acts of God; acts of the public enemy, war, hostilities, invasion, insurrection, riot, civil disturbance, or order of any competent civil or military government; explosion or fire; strikes or lockouts or other industrial action (excluding those of the Claiming Party unless such action is part of a wider industrial dispute materially affecting other employers); labor or material shortage; malicious acts, vandalism or sabotage; action or restraint by court order of any public or governmental authority (so long as the Claiming Party has not applied for or assisted in the application for, and has opposed where and to the extent reasonable, such government action). Neither Party shall be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to Force Majeure, except for the obligation to pay any amount when due, provided that the Claiming Party:

11.1.1 gives prompt written notice to the other Party of the event or circumstance giving rise to the event of Force Majeure;

11.1.2 affords the other Party reasonable access to information about the event or circumstances giving rise to the event of Force Majeure;

11.1.3 takes commercially reasonable steps to restore its ability to perform its obligations hereunder as soon as reasonably practicable, provided that the Claiming Party shall not be obligated to take any steps that are not otherwise in accordance with Good Utility Practice; and

11.1.4 exercises commercially reasonable efforts to perform its obligations hereunder.

Section 12 - Reporting; Audit.

12.1 Regulatory Reporting.

12.1.1 TranServ shall have the authority to report in writing to FERC in respect of any compensation-related Dispute that arises between TranServ and Company pursuant to Section 3.6.

12.1.2 TranServ shall report in writing to FERC every six (6) months (commencing on the six (6) month anniversary of the Commencement Date and every six (6) months thereafter during the Term) in respect of (a) any concerns expressed by stakeholders and TranServ~~'~~'s response to same and (b) any issues or OATT provisions that hinder TranServ from performing its duties and obligations under this Agreement and the OATT.

12.1.3 In addition to the reports provided for above, TranServ shall make such other reports to Regulatory Authorities as may be required by applicable law and regulations or as may be requested by such Regulatory Authorities.

12.2 Books and Records. TranServ shall maintain full and accurate books and records pertinent to this Agreement, and TranServ shall maintain such books and records for a minimum of five (5) years following the expiration or early termination of this Agreement or longer if necessary to resolve a pending Dispute. Company will have the right, at reasonable times and under reasonable conditions, to inspect and audit, or have an independent third party inspect and audit, TranServ’s operations, books, and records (a) to ensure compliance with this Agreement, including TranServ’s performance of ITO Services in accordance with Section 1.3.1, (b) to verify any cost claims or other amounts due hereunder, and (c) to validate TranServ’s internal controls with respect to the performance of ITO Services. TranServ shall maintain an audit trail, including all original transaction records and timekeeping records, of all financial and non-financial transactions and activities resulting from or arising in connection with this Agreement as may be necessary to enable Company or the independent third party, as applicable, to perform the foregoing activities. Company shall be responsible for any costs and expenses incurred in connection with any such inspection or audit, unless such inspection or audit discovers that Company was charged inappropriate or incorrect costs and expenses, in which case, TranServ shall be responsible for a percentage of the costs and expenses incurred in connection with such inspection or audit equal to the percentage variance by which Company was charged inappropriate or incorrect costs and expenses. TranServ shall provide reasonable assistance necessary to enable Company or an independent third party, as applicable, to perform the foregoing activities and shall not be entitled to charge Company for any such assistance. Amounts incorrectly or inappropriately invoiced by TranServ to Company, whether discovered prior to or subsequent to payment by Company, shall be adjusted or reimbursed to Company by TranServ within twenty (20) days of notification by Company to TranServ of the error in the invoice.

Section 13 - Independent Contractor

13.1 TranServ, in performing ITO Services, shall not act as an agent or employee of Company, but shall be and act as an independent contractor and, except as established in Section 1.3.1, shall be free to perform ITO Services by such methods and in such manner as TranServ may choose, doing everything necessary to perform such ITO Services properly and safely and having supervision over and responsibility for the safety and actions of its employees and the suitability of its equipment. TranServ Personnel and TranServ Designees shall not be deemed to be employees and/or agents of Company. TranServ agrees that if any portion of ITO Services are subcontracted to TranServ Designees, such TranServ Designees shall be bound by and observe the conditions of this Agreement to the same extent as required of TranServ. In such event, Company strongly encourages the use of Minority Business Enterprises, Women Business Enterprises and Disadvantaged Business Enterprises, as defined under federal law and as certified by a certifying agency that Company recognizes as proper.

13.2 Notwithstanding any provision in this Agreement to the contrary, unless approved in writing by Company, TranServ shall not (and shall not permit any TranServ Personnel or TranServ Designee to):

13.2.1 Sell, lease, pledge, mortgage, encumber, convey, or make any license, exchange or other transfer, assignment or disposition of any property or assets of Company;

13.2.2 Enter into, amend, terminate, modify or supplement any contract or agreement (including any labor or collective bargaining agreement) on behalf, or in the name, of Company;

13.2.3 Except upon the approval of Company or pursuant to the direction of Company, take any action that would, to TranServ’s knowledge: (a) invalidate any warranty that runs to Company under any contract or agreement; or (b) release any person or entity from its obligations under any contract or agreement with Company;

13.2.4 Make any warranty or representation on behalf of Company;

13.2.5 Except as contemplated under Section 7.4, settle, compromise, assign, pledge, transfer, release or consent to the compromise, assignment, pledge, transfer or release of any claim, suit, debt, demand or judgment against or due by Company, or submit any such claim, dispute or controversy to arbitration or judicial process, or stipulate in respect thereof to a judgment, or consent to the same;

13.2.6 Pledge the credit of Company in any way in respect of any commitments for which it has not received express written authorization from Company; or

13.2.7 Engage in any other transaction on behalf of Company not permitted under this Agreement.

Section 14 - Taxes.

Each Party shall be responsible for the payment of its own taxes, including taxes based on its net income, employment taxes of its employees, taxes on any property it owns or leases, and sales, use, gross receipts, excise, value-added or other transaction taxes. Sales and/or use taxes, that become applicable to services performed within Minnesota, shall be added to TranServ fees and compensation otherwise herein described.

Section 15 - Notices.

15.1 Notices. All notices, requests, consents and other communications required or permitted hereunder shall be in writing, signed by the Party giving such notice or communication, and shall be deemed given: (a) upon receipt, when mailed by U.S. certified mail, postage prepaid, return receipt requested; or (b) upon the next business day, when sent by overnight delivery, postage prepaid using a recognized courier service.

If to Company:

LG&E/KU
VP, Transmission
220 West Main St
PO Box 32010
Louisville, KY 40232

If to TranServ:

TranServ International, Inc.
~~General Counsel~~Contracts Administration
3660 Technology Drive NE
Minneapolis, MN 55418

15.2 Changes. Either Party may, from time to time, change the names, addresses, facsimile numbers or other notice information set out in Section 15.1 by notice to the other Party in accordance with the requirements of Section 15.1.

Section 16 - Personnel and Work Conditions; NERC Requirements.

16.1 Applicable Laws and Safety. TranServ agrees to protect TranServ Personnel and TranServ Designees and be responsible for their performance of the ITO Services, and to protect Company’s facilities, property, employees and third parties from damage or injury. TranServ shall at all times be solely responsible for complying with any and all applicable laws and facility rules relating to health and safety, in connection with ITO Services and for obtaining (but only as approved by Company) all permits and approvals necessary to perform ITO Services. Without limiting the foregoing, TranServ agrees to strictly abide by and observe all standards of the Occupational Safety & Health Administration (“OSHA”) which are applicable to ITO Services, as well as Company’s Contractor Code of Business Conduct and Company’s Contractor/Subcontractor Safety Policy which are both hereby incorporated by reference (Contractor hereby acknowledges receipt of a copy of such Company’s Contractor Code of Business Conduct and Company’s Contractor/Subcontractor Safety Policy) and any other rules and regulations of the Company, all of which are provided to TranServ in writing and incorporated herein by reference. TranServ also agrees to review in good faith and execute any amendments and/or modifications that may be issued in the future by Company from time to time, with respect to Company’s Contractor Code of Business Conduct and/or any of its related policies which are the subject of this Section 16, provided however, that TranServ shall not be obliged by such requirement if the requirements conflicts with an alternate regulatory code of conduct imposed on TranServ. In the event TranServ subcontracts any of ITO Services to a TranServ Designee, TranServ shall notify Company in writing of the identity of TranServ Designee before utilizing TranServ Designee. TranServ shall require any TranServ Designees to complete the safety and health questionnaire and checklists provided by Company and shall provide a copy of such documents to Company upon request. TranServ shall conduct, and require such TranServ Designees to conduct, safety audits and job briefings during performance of ITO Services as applicable. In the event such TranServ Designee has no procedure for conducting safety audits and job briefings, TranServ shall include TranServ Designee in its safety audits and job briefings. All applicable safety audits shall be documented in writing by TranServ and such TranServ Designees. TranServ shall provide documentation of any and all audits identifying safety deficiencies and concerns and corrective action taken as a result of such audits to Company semi-monthly. TranServ further specifically acknowledges, agrees and warrants that TranServ has complied, and shall at all times during the term of this Agreement, comply in all respects with all laws, rules and regulations relating to the employment authorization of TranServ Personnel including, but not limited to, the Immigration Reform and Control Act of 1986, as amended, and the Illegal Immigration Reform and Immigrant Responsibility Act of 1996, as amended, whereby TranServ certifies to Company that TranServ has (a) properly maintained, and shall at all times during the term of this Agreement properly maintain all records required by Immigration and Customs Enforcement, such as the completion and maintenance of the Form I-9 for each TranServ employee; (b) that TranServ maintains and follows an established policy to verify the employment authorization of TranServ Personnel; (c) that TranServ has verified the identity and employment eligibility of all TranServ Personnel in compliance with all applicable laws; and (d) that TranServ is without knowledge of any fact that would render any TranServ Personnel or TranServ Designee ineligible to legally work in the United States. TranServ further acknowledges, agrees and warrants that any TranServ Designee shall be required to agree to these same terms as a condition to being awarded any subcontract for such ITO Services.

16.2 Hazards and Training. TranServ shall furnish adequate numbers of trained, qualified, and experienced TranServ Personnel suitable for performance of ITO Services. Such TranServ Personnel shall be skilled and properly trained to perform ITO Services and recognize all hazards associated with ITO Services. Without limiting the foregoing, TranServ shall participate in any safety orientation or other of Company’s familiarization initiatives related to safety and shall strictly comply with any monitoring initiatives as determined by Company.

16.3 Drug and Alcohol. TranServ shall develop and strictly comply with any and all drug and alcohol testing requirements as required by applicable laws. TranServ shall provide Company with a copy of its drug and alcohol testing requirements.

16.4 NERC Reliability Standards. The following additional provisions shall apply to the extent TranServ’s performance of ITO Services requires physical or electronic access to areas or assets which are located within physical security perimeters as defined by NERC’s Reliability Standards for the Bulk Electric Systems of North America (collectively, the “NERC Standards”), including without limitation any Company data center or control center. In the event of TranServ’s non-compliance with the NERC Standards referenced in this Section 16.4, Company shall notify TranServ in writing of the non-compliance and specify appropriate remedial actions.

16.4.1 Information Protection. Without compromising the confidentiality provisions in Section 10, TranServ shall at all times comply with the Company’s information protection program(s) as defined by CIP-003, R4. Among the information protected by this program are: (i) all operational procedures; (ii) lists of critical cyber assets; (iii) network topology or similar diagrams; (iv) floor plans of computing centers that contain critical cyber assets; (v) equipment layouts of critical cyber assets; (vi) disaster recovery plans; (vii) incident response plans; and (viii) security configuration information. TranServ shall protect this protected information from disclosure consistent with the program.

16.4.2 Access Revocation. TranServ shall immediately advise appropriate Company’s management if any TranServ Personnel or TranServ Designees who have key card access to a Company restricted area or electronic access to a protected system no longer require such access.

16.4.3 Training. If any TranServ Personnel require key card access to a Company restricted area or electronic access to a protected system, TranServ shall ensure that such personnel complete, and retake as requested, all necessary NERC training as requested by Company.

16.4.4 Personnel Risk Assessment. If any TranServ Personnel require key card access to a Company restricted area or electronic access to a protected system, TranServ shall ensure that Company receives necessary waivers and information from TranServ Personnel to complete, and repeat as necessary, such background checks as requested by

Company.

16.4.5 Continuing Obligations. TranServ further acknowledges that its compliance with the NERC Standards referenced in this Section 16.4 is a continuing obligation during and after the Term. Upon written notice to TranServ, Company shall have the absolute right to audit and inspect any and all information regarding TranServ''s compliance with this Section 16.4, and/or to require confirmation of the destruction of any documentation received from or regarding Company. TranServ is encouraged to contact Company''s Compliance Department pursuant to Section 16.5 to ensure TranServ understands and complies with this Section 16.4.

16.5 Compliance Department. The Company has a Compliance Department. Should TranServ have actual knowledge of violations of any of the herein stated policies of conduct in this Section 16, or in standards of performance detailed in Section 1.3.1, or have a reasonable basis to believe that such violations have occurred, whether by TranServ Personnel or a TranServ Designee, TranServ has an affirmative obligation to immediately report, at least on an anonymous basis, any such known violations to the Company''s Office of Compliance in care of Director, Compliance and Ethics, LG&E/KU Services, 220 West Main Street, Louisville, Kentucky 40202.

16.6 Equal Employment Opportunity. To the extent applicable, TranServ shall comply with all of the following provisions, which are incorporated herein by reference: (i) Equal Opportunity regulations set forth in 41 C.F.R. § 60-1.4(a) and (c), prohibiting employment discrimination against any employee or applicant because of race, color, religion, sex, or national origin; (ii) Vietnam Era Veterans Readjustment Assistance Act regulations set forth in 41 C.F.R. § 60-250.4 relating to the employment and advancement of disabled veterans and Vietnam era veterans; (iii) Rehabilitation Act regulations set forth in 41 C.F.R. § 60-741.4 relating to the employment and advancement of qualified disabled employees and applicants for employment; (iv) the clause known as "Utilization of Small Business Concerns and Small Business Concerns Owned and Controlled by Socially and Economically Disadvantaged Individuals" set forth in 15 USC § 637(d)(3); and (v) the subcontracting plan requirement set forth in 15 USC § 637(d).

Section 17 - Miscellaneous Provisions.

17.1 Governing Law. This Agreement and the rights and obligations of the Parties hereunder shall be governed by and construed in accordance with the laws of the Commonwealth of Kentucky, without giving effect to its conflicts of law rules.

17.2 Amendment. This Agreement shall not be varied or amended unless such variation or amendment is agreed to by the Parties in writing and accepted by applicable Regulatory Authorities. The Parties explicitly agree that neither Party shall unilaterally petition to FERC pursuant to the provisions of Sections 205 or 206 of the Federal Power Act to amend this Agreement or to request that FERC initiate its own proceeding to amend this Agreement. Nothing in this Section 17.2 shall be construed to limit or affect any other rights that the Parties may have as set forth in Section 8.4, the OATT or otherwise.

17.3 Liability of Affiliates. Any and all liabilities of Company and/or its Affiliates under this Agreement shall be several but not joint.

17.4 Publicity. TranServ shall not issue news releases, publicize or issue advertising pertaining to ITO Services or this Agreement without first obtaining the written approval of Company.

17.5 Assignment. Any assignment of this Agreement or any interest herein or delegation of all or any portion of a Party's obligations, by operation of law or otherwise, by either Party without the other Party's prior written consent shall be void and of no effect; provided, however, that consent will not be required for Company to assign this Agreement to an Affiliate or a successor entity that acquires all or substantially all of the operational business assets of the assigning entity whether by merger, consolidation, reorganization, sale, spin-off or foreclosure; provided, further, that such Affiliate or successor entity (a) agrees to assume all obligations hereunder from and after the date of such assignment and (b) has the legal authority and operational ability to satisfy the obligations under this Agreement. As a condition to the effectiveness of such assignment (i) the assignor shall promptly notify the other Party of such assignment, (ii) the Affiliate or successor entity shall provide a confirmation to the other Party of its assumption of assignor's obligations hereunder, and (iii) assignor shall promptly reimburse the other Party, upon receipt of an invoice, for any one-time incremental costs reasonably incurred as a result of such assignment. For the avoidance of doubt, nothing herein shall preclude Company from transferring any or all of its transmission facilities to another entity or disposing of or acquiring any other transmission assets. Notwithstanding anything to the contrary contained in this Section 17.5, TranServ shall be entitled to contract with one or more persons (each, an "TranServ Designee") to perform only those ITO Services which the OATT expressly provides for being performed by a "designee" of TranServ (as opposed to TranServ or TranServ Personnel), provided that TranServ shall not be relieved of any of its obligations, responsibilities or liabilities under this Agreement as a result of contracting with one or more TranServ Designees in accordance with this Section 17.5 and shall be responsible and liable for any ITO Services performed by TranServ Designees.

17.6 No Third Party Beneficiaries. Except as otherwise expressly provided in this Agreement, this Agreement is made solely for the benefit of the Parties and their successors and permitted assigns and no other person shall have any rights, interest or claims hereunder or otherwise be entitled to any benefits under or on account of this Agreement as third party beneficiary or otherwise.

17.7 Waivers. No waiver of any provision of this Agreement shall be effective unless it is signed by the Party against which it is sought to be enforced. The delay or failure by either Party to exercise or enforce any of its rights or remedies under this Agreement shall not constitute or be deemed a waiver of that Party's right thereafter to enforce those rights or remedies, nor shall any single or partial exercise of any such right or remedy preclude any other or further exercise thereof or the exercise of any other right or remedy.

17.8 Enforcement of Rights. Each Party shall have the right to recover from the other Party all expenses, including fees for and expenses of inside and/or outside counsel, arising out of the other Party's breach of this Agreement or any other action to enforce or defend rights hereunder.

17.9 Severability; Renegotiation. The invalidity or unenforceability of any portion or provision of this Agreement shall in no way affect the validity or enforceability of any other portion or provision herein. If any provision of this Agreement is found to be invalid, illegal or otherwise unenforceable, the same shall not affect the other provisions hereof or the whole of this Agreement and shall not render invalid, illegal or unenforceable this Agreement or any of the remaining provisions of this Agreement. If any provision of this Agreement or the application thereof to any person, entity or circumstance is held by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, or if a modification or condition to this Agreement is imposed by such court or regulatory authority, the Parties shall in good faith negotiate such amendment or amendments to this Agreement as will restore the relative benefits and obligations of the Parties immediately prior to such holding, modification or condition.

17.10 Remedies. No remedy conferred by any of the provisions of this Agreement is intended to be exclusive of any other remedy available at law or equity or otherwise. The election of one or more remedies shall not constitute a waiver of the right to pursue any other available remedies.

17.11 Representations and Warranties. Each Party represents and warrants to the other Party as of the date hereof as follows:

17.11.1 Organization. It is duly organized, validly existing and in good standing under the laws of the State in which it was organized, and has all the requisite power and authority to own and operate its material assets and properties and to carry on its business as now being conducted and as proposed to be conducted under this Agreement.

17.11.2 Authority. It has the requisite power and authority to execute and deliver this Agreement and, subject to the procurement of applicable regulatory approvals, to perform its obligations under this Agreement. The execution and delivery of this Agreement by it and the performance of its obligations under this Agreement have been duly authorized by all necessary corporate action required on its part.

17.11.3 Binding Effect. Assuming the due authorization, execution and delivery of this Agreement by the other Party, this Agreement constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency or other similar applicable laws affecting creditors’’ rights generally, and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

17.11.4 Regulatory Approval. It has obtained or will obtain by the Commencement Date, any and all approvals of, and acceptances for filing by, and has given or will give any notices to, any applicable federal or state authority, including FERC and the KPSC (as applicable), that are required for it to execute, deliver, and perform its obligations under this Agreement.

17.11.5 No Litigation. There are no actions at law, suits in equity, proceedings, or claims pending or, to its knowledge, threatened against it before or by any federal, state, foreign or local court, tribunal, or governmental agency or authority that might materially delay, prevent, or hinder the performance by such entity of its obligations hereunder.

17.11.6 No Violation or Breach. The execution, delivery and performance by it of its obligations under this Agreement do not and shall not: (a) violate its organizational documents; (b) violate any applicable law, statute, order, rule, regulation or judgment promulgated or entered by any applicable federal or state authority, which violation could reasonably be expected to materially adversely affect the performance of its obligations under this Agreement; or (c) result in a breach of or constitute a default of any material agreement to which it is a party.

17.11.7 No Other Warranties. EXCEPT AS PROVIDED IN THIS AGREEMENT, TRANSERV MAKES NO OTHER WARRANTIES OF ANY KIND, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE.

17.12 Further Assurances. Each Party agrees that it shall execute and deliver such further instruments, provide all information, and take or forbear such further acts and things as may be reasonably required or useful to carry out the purpose of this Agreement and are not inconsistent with the provisions of this Agreement.

17.13 Entire Agreement. This Agreement and the Attachments hereto set forth the entire agreement between the Parties with respect to the subject matter hereof, and supersede all prior agreements, whether oral or written, related to the subject matter of this Agreement. The terms of this Agreement and the Attachments hereto are controlling, and no parole or extrinsic evidence, including to prior drafts and drafts exchanged with any third parties, shall be used to vary, contradict or interpret the express terms and conditions of this Agreement.

17.14 Good Faith Efforts. Each Party agrees that it shall in good faith take all reasonable actions necessary to permit it and the other Party to fulfill their obligations under this Agreement. Where the consent, agreement or approval of any Party must be obtained hereunder, such consent, agreement or approval shall not be unreasonably withheld, delayed or conditioned. Where a Party is required or permitted to act, or omit to act, based on its opinion or judgment, such opinion or judgment shall not be unreasonably exercised, other than where expressly provided for herein. To the extent that the jurisdiction of any federal or state authority applies to any part of this Agreement or the transactions or actions covered by this Agreement, each Party shall cooperate with the other Party to secure any necessary or desirable approval or acceptance of such authorities of such part of this Agreement or such transactions or actions.

17.15 Time of the Essence. With respect to all duties, obligations and rights of the Parties specified by Regulatory Authorities, time shall be of the essence in this Agreement.

17.16 Interpretation. Unless the context of this Agreement otherwise clearly requires:

17.16.1 all defined terms in the singular shall have the same meaning when used in the plural and vice versa;

17.16.2 the terms "hereof," "herein," "hereto" and similar words refer to this entire Agreement and not to any particular Section, Attachment or any other subdivision of this Agreement;

17.16.3 references to "Section" or "Appendix" refer to this Agreement, unless specified otherwise;

17.16.4 references to any law, statute, rule, regulation, notification or statutory provision shall be construed as a reference to the same as it applies to this Agreement and may have been, or may from time to time be, amended, modified or re-enacted;

17.16.5 references to "includes," "including" and similar phrases shall mean "including, without limitation;"

17.16.6 the captions, section numbers and headings in this Agreement are included for convenience of reference only and shall not in any way affect the meaning or interpretation of this Agreement;

17.16.7 "or" may not be mutually exclusive, and can be construed to mean "and" where the context requires there to be a multiple rather than an alternative obligation; and

17.16.8 references to a particular entity include such entity~~'~~'s successors and assigns to the extent not prohibited by this Agreement.

17.17 Joint Effort. Preparation of this Agreement has been a joint effort of the Parties and the resulting document shall not be construed more severely against one of the Parties than against the other and no provision in this Agreement is to be interpreted for or against any Party because that Party or its counsel drafted such provision. Each Party acknowledges that in executing this Agreement it has relied solely on its own judgment, belief and knowledge, and such advice as it may have received from its own counsel, and it has not been influenced by any representation or statement made by the other Party or its counsel not contained in this Agreement.

17.18 Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument, binding upon Company and TranServ, notwithstanding that Company and TranServ may not have executed the same counterpart.

The Parties have caused this Independent Transmission Organization Agreement to be executed by their duly authorized representatives as of the dates shown below.

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY

____
Name:
Title:
Date:

TRANSERV INTERNATIONAL, INC.

____
Name:
Title:
Date:

Appendix A
Louisville Gas and Electric Company/
Kentucky Utilities Company

INDEPENDENT TRANSMISSION ORGANIZATION

SERVICE SPECIFICATION

TABLE OF CONTENTS

1. ~~1.~~ Overview

This Appendix A is intended to be consistent with the terms and conditions of the LG&E/KU Open Access Transmission Tariff (OATT), including Attachment P thereto. If there is any conflict between this Appendix A and the OATT, the OATT shall govern. TranServ shall perform its obligations under this Appendix A in accordance with Section 1.3.1 of this Agreement.

The services delegated to TranServ include the administration of the LG&E/KU Open Access Same-time Information System (OASIS), transmission service request evaluation process, Available Transfer Capability (ATC)/ Available Flowgate Capability (AFC) management, study queue administration, study performance, and stakeholder facilitation. TranServ, as the ITO, will administer the OATT granting of service for both short and long-term transmission requests, administer the large generator interconnection request queue, and perform transmission studies. TranServ will facilitate the LG&E/KU long-term transmission planning function and stakeholder processes.

2. Definitions

Company - Louisville Gas and Electric Company/Kentucky Utilities Company (LG&E/KU)

ITO - Independent Transmission Organization

ITO Services - The applicable functions to be performed as specified in the ITO Agreement

RC - Reliability Coordinator

Service Interruption - A Service Interruption is the loss of Service function, under the direct control of TRANSERV with no mutually agreed to work around provided within the Service

Normal Business Hours - TranServ normal business hours are between the hours of 0700 and 1700 CT, Monday-Friday on days other than the holidays listed below:

1. New Year's Day
2. Memorial Day
3. Independence Day
4. Labor Day
5. Thanksgiving
6. Day after Thanksgiving
7. Day before Christmas
8. Christmas Day

3. Roles and Responsibilities for Providing ITO Services

3.1 TranServ

TranServ International, Inc. (TranServ) will provide services to LG&E/KU as the ITO. The services that TranServ will provide include:

3.1.1 Customer Interface

Responsibility for operating and maintaining OASIS website and keeping it up-to-date with Federal Energy Regulatory Commission (FERC) and North American Energy Standards Board (NAESB) posting requirements, including all Order No. 890 posting requirements (such as study performance metrics, Available Transfer Capability (ATC) calculations, etc.). This includes establishing an interface for customers to submit service requests, and oversight and evaluation of ATC values calculated using software procured from Open Access Technology International, Inc. (OATI) and information from the RC. TranServ's responsibilities and duties in administering OASIS will include the following:

- Performing the duties of a Responsible Party as defined in the Commission's OASIS regulations, 18 C.F.R. § 37.5 and FERC Order No. 676.
- Posting information required to be on the Transmission Provider's OASIS under the Commission's OASIS regulations, 18 C.F.R. § 37.6 and FERC Order No. 676.
- Maintaining and retaining information posted on OASIS in accordance with the Commission's regulations, including 18 C.F.R. Parts 37 and 125.
- Establishing and maintaining queues for processing transmission service requests and generator interconnection (GI) requests.
- Participating in the drafting and posting of Business Practices on the OASIS website, including any FERC or NAESB-required Business Practices. Company shall have final review, ownership, and approval for all Business Practices.
- Participating in periodic reviews of, and providing expertise/comments on, the OATT. Company retains final authority over the OATT's content, including retaining the right and responsibility to file changes to the OATT.
- Participating in stakeholder meetings and/or conference calls as required. These stakeholder meetings will include TranServ, Company, Customers (as appropriate) the

RC, and other entities as required, to address concerns regarding Company''s system, administration of the OATT, and related issues.

- Responsibility for coordinating with third-party transmission system owners and operators as necessary to support customer service requests. This includes coordinating the provision of any data from Company to the third-party system.
- Management of ATC/AFC Calculation and Posting.
- Implementation of certain aspects of the Congestion Management Process (CMP) established by the Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection LLC (PJM), and TVA.
- Administration of request evaluations for LG&E/KU tariff service.
- Processing of e-Tags as the transmission provider.
- Reviewing software changes requested from OATI, verifying and testing for proper operations before OATI implements those changes.

3.1.2 Transmission Service and Generator Interconnection Requests and Studies

- Receive and process all applications for Point-to-Point, Network Integration Transmission Service (NITS), and for GIs.
- For short-term Point-to-Point Transmission Service requests (i.e., where the request is within the posted ATC horizon), evaluate and approve a request where the posted ATC is sufficient for the requested transaction. If ATC is insufficient, TranServ shall propose conditional service options to the customer in accordance with the OATT, or otherwise deny the service. If the customer accepts conditional service options, TranServ will be responsible for performing biennial reassessments, as provided under the OATT.
- For long-term Point-to-Point Transmission Service requests, NITS, or GI requests:
  - Determine whether a System Impact Study (SIS) is necessary to accommodate the request.
  - Render all study agreements (SIS, Interconnection Feasibility Studies (IFS), Facilities Study (FS), and Feasibility Analysis Studies (FAS)) to customers within the timeframe provided in the OATT.
  - Perform the SIS or FAS in the timeframe provided in the OATT, including

clustered SISs when requested by customers and/or Company.

- Perform the SIS or FAS using Company's planning criteria.
- For any study that TranServ performs that requires information from Company (e.g., good faith construction estimates that are included in the SIS), request such information from Company no less than ten (10) business days before the expiration of the applicable study period.
- Complete study reports and post on OASIS within the timeframe required under the OATT.
- Notify the Company and individual customers of completed study reports, and alert the Company to initiate service agreements, if applicable.
- Receive customer deposits.
- Bill customers for SIS, IFS, FS, and FAS as required by the OATT, including provision of an itemized bill for services if requested by a customer.
- Reimburse Company for any study costs incurred in contributing to the study and render payment to any third-party vendors for work performed.

- Responsible for receiving and processing requests to designate or un-designate Network Resources, as provided under the OATT.
- If a customer requests a modification to its service, or if a customer assigns its transmission service to a third-party who request modification to the service, process those modification requests in accordance with the terms of the OATT.
- Track all study metrics, including data submittals, input validations, modifications, time and costs associated to perform the study.
- Track the performance of all studies and alert Company if a FERC filing requirement or penalty payment has been triggered due to late studies, as described under the OATT.

3.1.3 ATC Calculation

- Calculate ATC as provided for in Attachment C to the OATT. This includes receiving initial AFC values from the RC, calculating final AFC values using the algorithms included in Attachment C, and converting the AFC to ATC using OATI software.
- Post on OASIS the mathematical algorithms used to calculate firm and non-firm AFC.

TranServ shall also post the results of the AFC calculations on OASIS.

- Daily review of transmission service requests (TSRs) and eTag action and statistics.
- Daily review of posted AFC/ATC information and investigation into any anomalies.
- Review, observation, and validation of the Total Transfer Capability (TTC) development process.

3.1.4 Interchange and Scheduling

- As the Transmission Service Provider, responsible for the following activities:
  - Confirm that each electronic schedule (e-Tag) has a confirmed transmission service request.
  - Approve the interchange schedules as the transmission service provider.
  - Curtail electronic schedules if requested by the RC or Balancing Authority (BA).
  - Monitor and validate the Net Scheduled Interchange (NSI), as processed by OATI software, to ensure timely creation of the NSI data file with a syntactical quality check on the data set.

3.1.5 Transmission Planning

- TranServ will participate in Company''s transmission planning process as outlined in Attachment K to the OATT, including the following activities:
  - Review and approve Company''s long-term (generally one year and beyond) plan for the reliability/adequacy of Company''s Transmission System.
  - Review and approve Transmission System models (steady state, dynamics, and short circuit).
  - Develop alternatives to Planning Redispatch service.
  - Notify impacted transmission entities of any planned transmission changes that may influence their facilities.
  - Participate with the SPC and associated SPC working groups, as required.
  - Participate in the overall OATT Attachment K process as observer.

- The Parties agree that the final annual transmission plan and decision of whether/when to construct and expand the system rests with Company.
- Both parties will communicate openly and in a timely manner; each will perform their respective work; and both will continually work together to improve mutual and individual processes in a joint effort to assure work is completed pursuant to Company standards and deadlines.

3.1.6 Compliance

- Establish and adhere to a "culture of compliance" for TranServ Personnel and TranServ Designees consistent with FERC's Policy Statement on Compliance, 125 FERC ¶ 61,058 (2008) as may be supplemented or amended by further FERC orders. TranServ shall take such reasonable steps requested by the Company in furtherance of such a culture of compliance.
- In accordance with *Louisville Gas and Electric Company*, 114 FERC ¶ 61,282 at P 152 (2006), provide FERC with semi-annual reports "detailing concerns expressed by stakeholders and [ITO's] response to those concerns as well as any issues or tariff provisions that hinder [ITO] from performing its required duties" as requested.
- Maintain records and provide reports as required by the Kentucky Public Service Commission (KPSC), OATT, Department of Energy (DOE), FERC, NERC, SERC Reliability Corporation (SERC) or NAESB. Without limiting the foregoing, Company may from time-to-time provide TranServ with specific direction as to records that Company expects to support compliance efforts, and TranServ shall maintain such records as directed.
- Assist Company, as requested by Company, in the preparation of applications, audit materials, filings, reports or responses to any Regulatory Authority. Without limiting the foregoing, this assistance may include from time-to-time preparation for (and participation in, if appropriate) FERC or NERC audits and providing event analysis information for FERC, NERC or SERC. TranServ's support shall be provided in a time frame reasonably requested by Company.
- Monitor FERC, NERC, SERC, and NAESB activities for changes in standards or compliance requirements that may require modification to the ITO Services or other coordination with Company. To the extent possible, TranServ shall notify Company of any proposed or pending modifications prior to their implementation. The Parties shall work together to establish a work plan and timetable for implementation of any such

changes. The Parties agree that all changes to ITO Services resulting from legal and regulatory developments as well Company requests, shall be assessed using the change order process detailed in Section 5 of this Appendix A.

3.2 Transmission Planner

TranServ will provide certain services to LG&E/KU, the Transmission Planner (TP). The services include:

3.2.1 Customer Interface

- TranServ will participate in the drafting of Business Practices; including any FERC or NAESB required Business Practices. Company shall have final review, ownership, and approval for all Business Practices.
- TranServ will participate in periodic reviews of, and provide expertise/comments on the OATT. Company retains final authority over the OATT's content, including retaining the right and responsibility to file changes to the OATT.
- Responsible for planning, coordinating and holding regular stakeholder meetings and/or conference calls. These stakeholder meetings will include TranServ, Company, and the RC, and other entities as required, to address concerns regarding Company's system, administration of the OATT, and related issues. This activity includes (as necessary) performing background checks for stakeholders who desire access to Critical Energy Infrastructure Information (CEII), preparing meeting materials, facilitating the meeting, and preparing post-meeting minutes for posting on OASIS.
- Responsible for coordinating with third-party transmission system owners and operators as necessary to support customer service requests. This includes coordinating the provision of any data from Company to the third-party system.

3.3 LG&E/KU

TranServ understands that Company has the following responsibilities in support of the ITO Services under this Appendix A:

3.3.1 Customer Interface

- Contracting for the OATI ~~webOASIS~~webSmartOASIS service that meets FERC and NAESB requirements.

- Contracting for the OATI webTrans service used to evaluate and take actions on transmission service requests and e-Tags.
- Continuation of Agreement with the RC to provide necessary data for AFC/ATC calculation and posting processes.
- Final review, ownership, and approval for all Business Practices.
- Final authority over the OATT''s content, including the right and responsibility to file changes to the OATT.
- Cooperate in the coordination with third-party systems as necessary to support customer service requests. This includes coordinating the provision of any data from Company to the third-party system.

3.3.2 Compliance

- From time-to-time provide TranServ with specific direction as to records that Company expects to support compliance efforts, TranServ shall maintain such records as directed in order to provide reports as required by the KPSC, OATT, DOE, FERC, NERC, SERC or NAESB.
- Respond to TranServ notifications of FERC, NERC, SERC, and NAESB activities for changes in standards or compliance requirements that may require modification to the ITO Services or other coordination with Company within requested response timelines. Work together with ITO to establish a work plan and timetable for implementation of any such changes. The Parties agree that all changes to ITO Services resulting from legal and regulatory developments as well Company requests, shall be assessed using the change order process detailed in Section 5 of this Appendix A.

4. Customer Support

TranServ will provide support for Service 24-hours per day and 365-days per year by utilizing a single point of contact support staff. During Normal Business Hours the support staff can be contacted by telephone or by e-mail as outlined in published TranServ's ITO Support Information. After Normal Business Hours support is achieved through telephone only. TranServ will take all reasonable effort to ensure that reported problems or other Customer support related events are responded to within 30-minutes of the event notification when ITO Support Procedures are followed.

4.1 Problem Resolution

Problems or outages are reported to TranServ by following customer support processes. All problems or questions are assigned a severity level by mutual agreement of the parties. Problems which are considered Critical or High in severity should be reported to TranServ at any time. Problems considered Medium or Low severity should be reported by phone during business hours or by e-mail at any time. The severity level classifications are defined as follows:

Critical - Problems or issues that are impacting business immediately or impacting grid reliability and action is required prior to next business day.

High - Problems or issues that affect a key functionality of Service component and there is no work around available but immediate business or grid reliability impact is not present.

Medium - Business processes are impacted, but satisfactory work around is in place to avoid business interruptions.

Low - Customer inquiries or reported problems and issues that create nuisances or inconveniences for the customer. Minimal or no business impact is occurring.

Ticket Resolution		
Action	**TranServ Responsibility**	**Time To Remedy**
Correct a "Critical" severity Problem or Issue	During normal business hours TranServ will respond to reported Critical severity problems and begin corrective action immediately until either a satisfactory work around is in place or problem is resolved. Outside of normal business hours TranServ will respond to reported Critical severity problems within 30-minutes of notification. Escalation to responsible TranServ senior management will occur in all cases.	TranServ will work continuously until resolution is in place. This may include a temporary work around until a permanent correction can be implemented. **Performance goal is to resolve all Critical severity tickets within 4-hours.**
Correct a "High" severity Problem or Issue	During normal business hours TranServ will respond to reported High severity problems and begin corrective action to resolve with either a satisfactory work around or problem resolution prior to end of business day. Outside of normal business hours TranServ will respond to reported High severity problems within 30-minutes of notification. Escalation to responsible TranServ senior management will occur in all cases.	TranServ will provide an initial problem analysis update within 8-hours at all times. This may include a recommended temporary work around until a permanent correction can be implemented. **Performance goal is to resolve all High severity tickets within 24-hours.**
Correct a "Medium" severity Problem or Issue	TranServ will schedule corrective action jointly with Customer. Problems of Medium severity should be reported by telephone during business hours or by e-mail at any time.	TranServ will provide an initial problem analysis update within 3-business days of notification of problem. An appropriate action plan and resolution schedule will be mutually agreed to with the Customer. **Performance goal is to resolve all Medium severity tickets by agreed to commitment date.**
Correct a "Low" severity Problem or Issue	TranServ will schedule corrective action jointly with Customer. Problems of Low severity should be reported by telephone during business hours or by e-mail at any time.	TranServ will provide an initial problem analysis update within 5-business days. An appropriate action plan and resolution schedule will be mutually agreed to with the Customer. **Performance goal is to resolve all Low severity tickets by agreed to commitment date.**

4.1.1 Tickets - OATI webSupport

To ensure all customers of TranServ receive a high level of customer service all calls or e-mails with questions or reported problems are documented in a Ticket. All TranServ staff members utilize OATI webSupport, an issue reporting and assignment platform allowing tracking and confirmed resolution of all issues reported to TranServ. Upon receiving a communication from a customer, TranServ will open a webSupport Ticket. The Ticket contains customer contact information, data metrics on the type of problem, an identification of the TranServ staff member to whom the Ticket is currently assigned, a detailed description of the problem, and a detailed description of the problem's current status which will eventually include a description of how the issue was resolved. The TranServ staff member provides the Ticket number to the customer for all issues not resolved immediately. If the issue cannot be resolved by the TranServ staff member creating the Ticket, the Ticket is reassigned to another member of the TranServ team. The TranServ staff member who initially created the Ticket is expected to use webSupport's monitoring capability to determine unresolved Tickets, and to reassign or escalate it as necessary at any time to promote prompt resolution within response timing guidelines.

4.1.2 Response Time

TranServ support staff will answer all calls as received during normal business hours and take all reasonable effort to resolve issues at the time of call. For issues and problems that are not immediately resolved, TranServ will follow normal processing for assigned severity level and notify customer once resolution occurs.

Calls to support staff outside of normal business hours will be answered as received and customer will be notified within 30-minutes on planned actions to be taken by TranServ support staff in accordance with normal processing for assigned severity level.

4.1.2.1 Ticket Escalation

Problem tickets that cannot be resolved in accordance with normal processing for assigned severity level will be escalated to appropriate TranServ management. Customers may request immediate ticket escalation to appropriate TranServ management.

4.1.2.2 Customer Satisfaction

Customer satisfaction inquiries are automatically sent to customers upon the closing of a ticket. The results of these surveys result in improved performance by customer support staff or changes in business processes.

5. Service Modifications

From time to time Company may require a modification to an existing Service function. Such modifications may be prompted by changes in regulatory compliance requirements, or by a Company request. Minor modifications that require reasonably minimal resource commitment from TranServ staff will be included within a reasonable time period at no cost to Company. Modifications that may have more significant impact on Service design or will impact TranServ staff resource commitments more than minimally will be discussed with Company and may in some instances require additional payment by Company, or likewise, require a decrease in payment by Company. Each of these change requests will be described in a written Change Order. Each Change Order will be scheduled for implementation upon written agreement with Company as to scope, cost and schedule.

5.1 Minor Changes

Any change to an existing Service function that does not have a significant impact on Service design or require TranServ to staff or contract with additional personnel, if even for a brief period of time, to prepare for and/or meet the requirements of the change (a "Minor Change") will be integrated into Company's Service at no cost to Company. A written Change Order will be negotiated and executed between Company and TranServ prior to implementation of any Minor Change.

5.2 Major Changes

Any change to an existing Service function that has a significant impact on Service design or requires TranServ to staff additional or fewer personnel, if even for a brief period of time, in order to prepare for and/or meet the requirements of the change (a "Major Change") will require a written Change Order which must be negotiated and executed between Company and TranServ prior to implementation of any Major Change.

6. Reliability Coordination

TranServ will be required to coordinate its operations with the LG&E/KU designated RC. The RC is responsible for performing certain reliability related tasks for the LG&E/KU system, including acting as the NERC-registered Reliability Coordinator. The RC's responsibilities are detailed in the Reliability Coordinator Agreement and Attachment P to the LG&E/KU OATT.

Document comparison by Workshare Professional on Monday, December 19, 2016 9:18:58 AM

Input:	
Document 1 ID	file://C:\Users\nallscm\Documents\LGE-KU\ITO - TransServ Agreement\2014 Agreement.rtf
Description	2014 Agreement
Document 2 ID	file://C:\Users\nallscm\Documents\LGE-KU\ITO - TransServ Agreement\ITO (TranServ) Contract - Final 12-1-2016 (2).docx
Description	ITO (TranServ) Contract - Final 12-1-2016 (2)
Rendering set	Standard

Legend:	
Insertion	
~~Deletion~~	
~~Moved from~~	
Moved to	
Style change	
Format change	
~~Moved deletion~~	
Inserted cell	
Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

Statistics:	
	Count
Insertions	262
Deletions	260
Moved from	0
Moved to	0
Style change	0
Format changed	0
Total changes	522

FERC rendition of the electronically filed tariff records in Docket No. ER17-00850-000
Filing Data:
CID: C000553
Filing Title: ITO Agreement 2017-2022 Att. Q
Company Filing Identifier: 147
Type of Filing Code: 10
Associated Filing Identifier:
Tariff Title: Transmission
Tariff ID: 3
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Part V_ATTACH Q, Part V_ATTACH Q Agts btw TO and ITO and RC, 12.0.0, A
Record Narative Name:
Tariff Record ID: 70
Tariff Record Collation Value: 3155968 Tariff Record Parent Identifier: 2
Proposed Date: 2017-09-01
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT Q

AGREEMENTS BETWEEN THE TRANSMISSION OWNER AND THE ITO AND THE RELIABILITY COORDINATOR

Independent Transmission Organization Agreement

Between

Louisville Gas and Electric Company/
Kentucky Utilities Company

And

TranServ International, Inc.

FINAL

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Appendix A - Service Specification

INDEPENDENT TRANSMISSION ORGANIZATION AGREEMENT

This Independent Transmission Organization ("ITO") Agreement (this "Agreement") is entered into on September 1, 2017, between Louisville Gas and Electric Company and Kentucky Utilities Company, corporations organized pursuant to the laws of the Commonwealth of Kentucky (collectively, "Company"), and TranServ International, Inc., an entity organized pursuant to the laws of Delaware ("TranServ"). Company and TranServ may sometimes be individually referred to herein as a "Party" and collectively as the "Parties."

WHEREAS, Company owns, among other things, an integrated electric transmission system ("Transmission System"), over which open access transmission service is provided to customers in the Company's Balancing Authority Area (as that term is defined by the North American Electric Reliability Corporation ("NERC"));

WHEREAS, the Company has an Open Access Transmission Tariff ("OATT") on file with the Federal Energy Regulatory Commission ("FERC")

WHEREAS, Company's current contract with TranServ is scheduled to expire on August 31, 2017;

WHEREAS, Company desires that, upon expiration of the current contract, TranServ will continue its work under this Agreement, as detailed herein;

WHEREAS, Company remains the owner of its Transmission System and shall be the ultimate provider of transmission services to Eligible Customers (as defined in the OATT), including the sole authority to amend the OATT;

WHEREAS, TranServ: (i) is independent from Company; (ii) possesses the necessary competence and experience to perform the functions provided for hereunder; and (iii) is willing to perform such functions under the terms and conditions agreed upon by the Parties as set forth in this Agreement; and

WHEREAS, as part of Company's goal to maintain independence in the operation of its Transmission System in order to prevent any exercise of transmission market power, Company entered into a Reliability Coordinator Agreement (the "Reliability Coordinator Agreement") with the Tennessee Valley Authority, NERC-certified reliability coordinator (the "Reliability Coordinator"), pursuant to which the Reliability Coordinator provides to Company certain required reliability functions.

NOW THEREFORE, in consideration of the mutual promises contained herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties hereby agree as follows:

Section 1 - Services to be Provided; Standards of Performance

1.1 Services. TranServ shall perform, or cause to be performed, the services described in Appendix A hereto as well as any obligations expressly assigned to the ITO under the OATT ("ITO Services") during the Term in accordance with the terms and conditions of this Agreement, subject to modification pursuant to Section 1.4 hereto.

1.2 Coordination with Reliability Coordinator. In conjunction with its performance of ITO Services, TranServ shall coordinate and cooperate with the Reliability Coordinator in accordance with the terms of the OATT and all NERC and SERC Reliability Corporation ("SERC") requirements. TranServ shall provide to the Reliability Coordinator, subject to the terms and conditions of this Agreement, including TranServ's obligations with respect to Confidential Information in Section 10, any information that the Reliability Coordinator may reasonably request in order to carry out its functions under the Reliability Coordinator Agreement, which agreement is included in the OATT.

1.3 TranServ Performance; Compliance.

1.3.1 Performance. TranServ, TranServ Personnel and any TranServ Designee (as defined in Section 17.5) shall perform TranServ's obligations (including ITO Services) under this Agreement:

(a) in an independent, fair, and nondiscriminatory manner; and

(b) in accordance with:

(i) any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition ("Good Utility Practice"). Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 2 14(a)(4);

(ii) the terms and conditions of the OATT;

(iii) all applicable laws and the requirements of federal and state regulatory authorities, including the Kentucky Public Service Commission ("KPSC"), Department of Energy ("DOE"), FERC, NERC, SERC, and the North American Electric Standards Board ("NAESB") (collectively, "Regulatory Authorities"); and in fulfilling this requirement in this subsection (iii), TranServ will cooperate with all reasonable requests by Company for information, interviews with TranServ personnel, or other support that may be needed to investigate possible FERC, NERC or other compliance violations or prepare for or respond to compliance-related audits, self-certifications, and other inquiries by Regulatory Authorities (whether internal or external); and

(iv) any methodologies, processes, or procedures relating to ITO Services which Company may develop and which Company determines are necessary or appropriate to ensure safe and reliable system operations and compliance with all applicable laws and the applicable requirements of Regulatory Authorities.

1.4 Changes to ITO Services. The Parties agree that all changes to ITO Services resulting from legal and regulatory developments, as well as Company requests, shall be assessed using a change order process. This process will include a written assessment of impacts to ITO Services consistent with Section 5 of Appendix A. Changes will be implemented only after mutual execution of a change document, which may be titled a Change Order or an Amendment. If the Parties are unable to agree on whether a change constitutes a "Minor Change," or a "Major Change," as those terms are used in Section 5 of Appendix A, such Dispute shall be resolved in accordance with Section 3.6.

Section 2 - Independence and Standards of Conduct

2.1 TranServ Personnel. All ITO Services shall be performed by staff members of TranServ ("TranServ Personnel") or TranServ Designees. No TranServ Personnel or TranServ Designee shall also be employed by Company or any of its Affiliates (as defined in FERC's regulations, 18 C.F.R. § 35.34(b)(3) (2011)). TranServ, TranServ Employees, and TranServ Designees shall (i) be Independent of and (ii) shall not discriminate against Company, any of its Affiliates, or any Tariff Participant. For purposes of this Agreement: (a) "Independent" shall mean that TranServ, TranServ Personnel, and any TranServ Designees are not subject to the control of Company, its Affiliates or any Tariff Participant, and have full decision-making authority to perform all ITO Services in accordance with the provisions of this Agreement. Any TranServ Personnel or

TranServ Designee owning securities in Company, its Affiliates or any Tariff Participant shall divest such securities within six (6) months of first being assigned to perform such ITO Services, provided that nothing in this Section 2.1 shall be interpreted or construed to preclude any such TranServ Personnel or TranServ Designee from indirectly owning securities issued by Company, its Affiliates or any Tariff Participant through a mutual fund or similar arrangement (other than a fund or arrangement specifically targeted toward the electric industry or the electric utility industry or any segment thereof) under which the TranServ Personnel or the TranServ Designee does not control the purchase or sale of such securities. Participation by any TranServ Personnel or TranServ Designee in a pension plan of Company, its Affiliates or any Tariff Participant shall not be deemed to be a direct financial interest if the plan is a defined-benefit plan that does not involve the TranServ Personnel's or TranServ Designee's ownership of the securities; and (b) "Tariff Participant" shall mean Company Transmission System customers, interconnection customers, wholesale customers, affected transmission providers, any Market Participant (as defined in FERC's regulations, 18 C.F.R. § 35.34(b)(2) (2011)) and similarly qualified third parties within the Company Balancing Authority Area. For the avoidance of doubt, Company shall have no veto authority over the selection of TranServ Personnel or TranServ Personnel matters, including TranServ's appointment of a TranServ Project Manager (as provided in Section 8.2) except that the Company and TranServ hereby agree that TranServ shall be prohibited from hiring current or former Company employees until at least one (1) year subsequent to the Company employee's separation from Company. Likewise, Company is prohibited from hiring current or former TranServ employees until one (1) year subsequent to the TranServ employee's separation from TranServ.

2.2 Standards of Conduct Treatment. All TranServ Personnel and TranServ Designees performing work under this Contract shall be treated, for purposes of the FERC's Standards of Conduct (18 C.F.R. Part 358), as transmission function employees. All restrictions relating to information sharing and other relationships between marketing function employees and transmission function employees, as those terms are defined in the Standards of Conduct, including the non-discrimination requirements contained therein, shall apply to TranServ Personnel and TranServ Designees performing work under this Contract, or likely to become privy to transmission function information. Said TranServ Personnel and TranServ Designees shall participate in any Standards of Conduct training that the Company may request for compliance purposes. TranServ shall provide prompt notice of new TranServ Personnel or TranServ Designees to Company to assure new persons are trained within the first thirty (30) days of their employment with TranServ.

Section 3 - Compensation; Billing and Payment; Performance Review

3.1 Compensation for Services. Company shall pay to TranServ an annual fee for performance of the ITO Services ("Annual Fee"). The Annual Fee (subject to increases or decreases in accordance with Section 5 of Appendix A) shall be $2,479,543.56 for the first Contract Year and shall escalate by one and five/tenths percent (1.5%) of the prior year's Annual Fee for each Contract Year thereafter.

3.2 Out-of-Pocket Costs. Company shall reimburse TranServ for actual out-of-pocket third party costs and expenses, without markup, for (a) regulatory legal support that is reasonably allocable to TranServ's performance of ITO Services, provided that in no event shall Company reimburse TranServ for legal fees associated with any actual or potential Dispute under this Agreement, (b) travel and lodging that are reasonably allocable to TranServ's performance of ITO Services and (c) setting up regular stakeholder meetings (collectively, (a), (b) and (c) are "Out-of-Pocket Costs"); provided, however, that all Out-of-Pocket Costs subject to reimbursement under this Section 3.2 must be reviewed and approved by Company prior to TranServ incurring such expense.

3.3 Payment.

3.4.1 Monthly Payment. TranServ shall deliver to Company monthly invoices by regular mail, facsimile, electronic mail or such other means as the Parties agree. Such invoices shall set forth (i) one-twelfth (1/12) of the Annual Fee for each month in advance, and (ii) any Out-of-Pocket costs incurred during the previous month, provided however, that travel expenses occurring on the last three (3) days of each month may be carried over to future invoices for ease of administration. Company shall make payment of the amount invoiced by wire transfer in immediately available funds to an account specified by TranServ not later than the thirtieth (30^{th}) day after receipt of the invoice, unless such day is not a business day, in which case on the next business day. All such payments shall be deemed made when said wire transfer is received by TranServ. Overdue payments shall accrue interest calculated at the FERC interest rate as defined in 18 C.F.R. §35.19a(2)(iii)(A) (2011) ("FERC Interest Rate").

3.4 Annual Review.

3.4.1 Annual Review. Commencing at the end of each Contract Year, no later than sixty (60) days after the end of each Contract Year, TranServ shall determine and deliver to Company a calculation of TranServ's actual labor in providing ITO Services for the preceding Contract Year ("Annual Labor"). The Annual Labor calculation shall detail the job title and number of full-time employees assigned to ITO Services, and the number of hours spent in performing ITO Services. The Annual Labor shall also include the hours for any tasks which TranServ outsourced to TranServ Designees.

3.5 Compensation Disputes. Notwithstanding the Dispute resolution provisions in Section 8.3, for any Disputes concerning compensation under this Section 3, Company shall timely file notice of such Dispute with FERC and request that FERC resolve such Dispute. TranServ retains the authority to file notice with FERC of any such Dispute if it so desires. If either Party in good faith disputes any invoice submitted by the other Party pursuant to this Agreement, then the disputing Party (i) shall timely pay the other Party the entire invoiced amount and (ii) shall furnish the other Party with a written explanation specifying the amount of and the basis for the Dispute. Within twenty (20) days after resolution of such Dispute, the Party owing money shall pay the other Party the amount owed, if any, together with interest calculated at the FERC Interest Rate.

Section 4 - Term and Termination

4.1 Term. The initial term of this Agreement shall begin on September 1, 2017 ("Commencement Date"), and shall continue for five (5) years thereafter ("Initial Term"). At the conclusion of the Initial Term, this Agreement shall automatically extend for successive one

(1) year terms (each a "Subsequent Term"), unless terminated by either Party in accordance with the terms of this Agreement. Three hundred and sixty (360) days prior to the conclusion of the Initial Term either Party may notify the other, in writing, of a desire to amend terms or pricing of this Agreement for the Subsequent Terms. If such amendment is not agreed upon by both parties 180 days prior to the beginning of the first Subsequent Term, the Amendment shall not automatically extend and will terminate on the later of i) the conclusion of the Initial Term, as defined above, or ii) receipt of the regulatory approvals required under Section 4.5. The Initial Term or any Subsequent Terms are each referred to herein as a "Term." For the purposes of this Agreement, a "Contract Year" shall begin on the Commencement Date or anniversary thereof and conclude twelve (12) months thereafter.

4.2 Termination by Either Party. This Agreement may be terminated by either Party at the end of a Term upon prior one hundred eighty (180) days written notice to the other Party, which termination shall be effective upon the later of (i) one hundred eighty (180) days after the date of such written notice, or (ii) receipt of the regulatory approvals required under Section 4.5.

4.3 Immediate Termination.

4.3.1 Termination for Cause. Subject to Section 4.5, either Party may terminate this Agreement upon prior written notice thereof to the other Party if:

(a) Material Failure or Default. The other Party fails, in any material respect, to comply with, observe or perform, or defaults, in any material respect, in the performance of the terms and conditions of this Agreement, and such failure or default remains uncured for thirty (30) days after written notice thereof, provided that such failure or default is susceptible to cure and the other Party is exercising reasonable diligence to cure such failure or default;

(b) Pattern of Failure. It determines, in its reasonable discretion, that there has been a pattern of failure by the other Party to comply with the standards of performance set forth in Section 1.3.1, whether or not such failure is material;

(c) Gross Negligence, Willful Misconduct or Fraud. The other Party commits gross negligence, willful misconduct or fraud in the performance of its obligations under this Agreement;

(d) Material Misrepresentation. Any representation made by the other Party hereunder shall be false or incorrect in any material respect when made and such misrepresentation is not cured within thirty (30) days of such discovery or written notice thereof, or is incapable of cure;

(e) Bankruptcy. The other Party: (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it; (ii) makes an assignment or any general arrangement for the benefit of creditors; (iii) otherwise becomes bankrupt or insolvent (however evidenced); (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets; or (v) is generally unable to pay its debts as they fall due; or

(f) Dissolution. The other Party dissolves or is dissolved or its legal existence is otherwise terminated.

4.3.2 Immediate Termination Not For Cause. Subject to Section 4.5, Company may terminate this Agreement upon thirty (30) days prior written notice thereof to TranServ if:

(a) Failure to Negotiate Amendment. The Parties are unsuccessful in negotiating an amendment or amendments to this Agreement pursuant to Section 17.9;

(b) Regulatory Changes/Modifications. A Regulatory Authority makes any material changes, modifications, additions, or deletions to this Agreement, unless both Parties agree to such changes, modifications, additions, or deletions;

(c) Failure to Receive Regulatory Approval. Prior to the Commencement Date, FERC rejects this Agreement or Company's selection of TranServ as the ITO;

(d) RTO. Company joins a regional transmission organization ("RTO");or

(e) Extended Force Majeure. A Party is excused because of Force Majeure (as defined in Section 11) for more than thirty (30) days from performing any of its material obligations under this Agreement.

4.4 Termination for Lack of Independence. Subject to Section 4.5, Company may terminate this Agreement upon prior written notice thereof to TranServ if FERC or the KPSC issues a final order that declares that TranServ lacks independence from Company and TranServ cannot obtain independence in a reasonable manner or time period.

4.5 Regulatory Approval. No termination of this Agreement shall be effective until approved by FERC and the KPSC. Notice of termination provided pursuant to Sections 4.3 and 4.4 shall become effective immediately upon approval by FERC and the KPSC.

4.6 Return of Materials. Upon any termination of this Agreement TranServ shall timely and in an orderly manner turn over to Company all materials that were prepared or developed pursuant to this Agreement prior to termination, and return or destroy, at the option of Company, all Data and other information supplied by Company to TranServ or created by TranServ on behalf of Company.

4.7 Survival. All provisions of this Agreement which are by their nature or terms intended to survive the termination of this Agreement, including the obligations set forth in Section 7 and Section 10, shall survive termination of this Agreement.

4.8 Compensation for Early Termination.

4.8.1 If Company terminates this Agreement before the end of a Term pursuant to Section 4.3.2 (a), (b), (d) or (e), then Company shall pay to TranServ the Annual Fee(s) through the longer of the end of the Contract Year or for six (6) months subsequent to the date of termination, which fees shall be accelerated hereunder for this purpose, plus any unpaid Out-of-Pocket Costs that TranServ has incurred through the date of any such termination. In the event that this Section 4.8.1 should trigger an acceleration of Annual Fee(s) that would otherwise span multiple years, such fees paid by Company to TranServ shall not include any escalation of one and five/tenths percent (1.5%) as described in Section 3.1 that had not yet been previously applied to the Annual Fee(s).

4.8.2 If Company terminates this agreement before the end of the Term, and such termination is for cause pursuant to Section 4.3.1, then Company shall only be liable for TranServ's Out-of-Pocket Costs incurred pursuant to contracts which extend beyond any early termination date.

4.9 Post-Termination Services. Commencing on the date that any termination becomes effective ("Termination Date") and continuing for up to one hundred eighty (180) days thereafter, TranServ shall (a) provide ITO Services (and any replacements thereof or substitutions therefor), to the extent Company requests such ITO Services to be performed, and (b) cooperate with Company in the transfer of ITO Services (collectively, the "Post-Termination Services") as such services are authorized under a separate agreement between the Parties. TranServ shall, upon Company's request, provide the Post-Termination Services at a cost to be negotiated and mutually agreed to at that time. The quality and level of performance of ITO Services by TranServ shall not diminish. After the expiration of the Post-Termination Services, TranServ shall answer questions from Company regarding ITO Services on an "as needed" basis at TranServ's then-standard billing rates.

4.10 Termination for Guarantee Termination. A guaranty with Open Access Technology International, Inc., in favor of Company and with TranServ as a counterparty was executed (November 29, 2016) (hereinafter "the Guaranty"). Subject to Section 4.5, Company may terminate this Agreement if the Guaranty is terminated and TranServ does not provide a replacement Guaranty determined, by Company, to be satisfactory.

Section 5 - Data Management and Intellectual Property

5.1 Supply of Data. During the Term, Company shall supply to TranServ, and/or grant TranServ access to all Data that TranServ requests and that TranServ believes is necessary to perform its duties and obligations under this Agreement, including ITO Services. The Parties shall agree upon the initial format and manner in which such Data shall be provided. For purposes of this Agreement, "Data" means all information, text, drawings, diagrams, models, images or sounds which are embodied in any electronic or tangible medium and which (a) are supplied or in respect of which access is granted to TranServ by Company under this Agreement, which shall be Company's Data, (b) are prepared, stored or transmitted by TranServ solely on behalf of Company, which shall be Company's Data; or (c) are compiled by TranServ by aggregating Data owned by Company and Data owned by third parties, which shall be

TranServ's Data.

5.2 Property of Each Party. Each Party acknowledges that the other Party's Data and the other Party's software, base data models and operating procedures for software or base data models ("Processes") are the property of such other Party and agrees that it will do nothing inconsistent with such ownership, including preserving all intellectual property and/or proprietary rights in such other Party's Data and Processes as provided in Section 6.

5.3 Data Integrity. Each Party shall reasonably assist the other Party in establishing measures to preserve the integrity and prevent any corruption or loss of Data, and the Parties shall reasonably assist each other in the recovery of any corrupted or lost Data. Each Party shall reasonably retain and preserve any of the other Party's Essential Data that are supplied to it during the Term. "Essential Data" means any Data that is reasonably required to perform ITO Services under this Agreement and that must be retained and preserved according to any applicable law, regulation, reliability criteria, or Good Utility Practice. Each Party shall exercise commercially reasonable efforts to preserve the integrity of the other Party's Data that are supplied to it during the Term, in order to prevent any corruption or loss of the other Party's Data.

5.4 Confidentiality. Each Party's Data shall be treated as Confidential Information in accordance with the provisions of Section 10.

Section 6 - Intellectual Property.

6.1 Ownership. All inventions, discoveries, processes, methods, designs, drawings, blueprints, information, works of authorship, or the like, whether or not patentable or copyrightable (collectively, "Intellectual Property"), which TranServ first conceives, develops, or begins to develop, either alone or in conjunction with Company or others, with respect to ITO Services under this Agreement, shall be jointly owned by Company and TranServ, and each party shall have the right to use such intellectual property unless specifically otherwise specified on a change document hereunder.

6.2 Royalties and License Fees. Unless the Parties otherwise agree in writing, TranServ shall procure and pay all royalties and license fees which may be payable on account of ITO Services or any part thereof. In case any part of ITO Services is held in any suit to constitute infringement and its use is enjoined, TranServ within a reasonable time shall, at the election of Company and as Company's exclusive remedy hereunder, either (a) secure for Company the perpetual right to continue the use of such part of ITO Services by procuring for Company a royalty-free license or such other permission as will enable TranServ to secure the suspension of any injunction, or (b) replace at TranServ's own expense such part of ITO Services with a non-infringing part or modify it so that it becomes non-infringing (in either case with changes in functionality that are acceptable to Company).

Section 7 - Indemnification and Limitation of Liability

7.1 Company Indemnification. Subject to the limitations specified in Section 7.6, Company shall indemnify, release, defend, reimburse and hold harmless TranServ and its directors, officers, employees, principals, representatives and agents (collectively, the "TranServ

Indemnified Parties") from and against any and all third party claims (including claims of bodily injury or death of any person or damage to real and/or tangible personal property), demands, liabilities, losses, causes of action, awards, fines, penalties, litigation, administrative proceedings and investigations, costs and expenses, and attorney fees, (each, an "Indemnifiable Loss") asserted against or incurred by any of the TranServ Indemnified Parties arising out of, resulting from or based upon TranServ performing its obligations pursuant to this Agreement, provided, however, that in no event shall Company be obligated to indemnify, release, defend, reimburse or hold harmless the TranServ Indemnified Parties from and against any Indemnified Loss which is caused by the negligence, the gross negligence or willful misconduct of any TranServ Indemnified Party.

7.2 TranServ Indemnification. Subject to the limitations specified in Section 7.6, TranServ shall indemnify, release, defend, reimburse and hold harmless Company and its directors, officers, employees, principals, representatives and agents (collectively, the "Company Indemnified Parties") from and against any and all Indemnifiable Losses asserted against or incurred by any of the Company Indemnified Parties arising out of, resulting from or based upon TranServ's or a TranServ Designee's negligence, gross negligence, or willful misconduct, provided, however, that in no event shall TranServ be obligated to indemnify, release, defend, reimburse or hold harmless any Company Indemnified Parties from and against any Indemnified Loss which is caused by the negligence, gross negligence or willful misconduct of any Company Indemnified Party.

7.3 Regulatory Indemnification. Subject to the limitations specified in Section 7.6, TranServ shall indemnify, release, defend, reimburse and hold harmless any Company Indemnified Parties from and against all regulatory penalties and sanctions (including penalties or sanctions levied by a Regulatory Authority) arising out of, resulting from or based upon TranServ breach of this Agreement, specifically including Section 1.3.1 hereto, provided, however, that in no event shall TranServ be obligated to indemnify, release, defend, reimburse or hold harmless any Company Indemnified Parties from and against any penalty or sanction which is caused by the gross negligence or willful misconduct of any Company Indemnified Party.

7.4 Cooperation Regarding Claims. If an Indemnified Party (which for purposes of this Section 7.4 shall mean an TranServ Indemnified Party or a Company Indemnified Party) receives notice or has knowledge of any Indemnifiable Loss that may result in a claim for indemnification by such Indemnified Party against an Indemnifying Party (which for purposes of this Section 7.4 shall mean Company or TranServ) pursuant to this Section 7, such Indemnified Party shall as promptly as possible give the Indemnifying Party written notice of such Indemnifiable Loss, including a reasonably detailed description of the facts and circumstances relating to such Indemnifiable Loss, a complete copy of all notices, pleadings and other papers related thereto, and in reasonable detail the basis for its claim for indemnification with respect thereto. Failure to promptly give such written notice or to provide such information and documents shall not relieve the Indemnifying Party from the obligation hereunder to respond to or defend the Indemnified Party against such Indemnifiable Loss unless and only to the extent such failure shall materially diminish the ability of the Indemnifying Party to respond to or to defend the Indemnified Party against such Indemnifiable Loss. Except for indemnification for penalties and sanctions under Section 7.3, the Indemnifying Party, upon its acknowledgment in writing of its obligation to indemnify the Indemnified Party in accordance with this Section 7, shall be entitled to assume the defense or to represent the interest of the Indemnified Party with respect to such Indemnifiable Loss, which shall include the right to select and direct legal counsel and other consultants, appear in proceedings on behalf of such Indemnified Party and to propose, accept or reject offers of settlement, all at its sole cost. If and to the extent that the defense or settlement of any Indemnifiable Loss is reasonably likely to involve injunctive, equitable or prospective relief or materially and adversely affect the Indemnified Party's business or operations other than as a result of money damages or other money payments assumed by the Indemnifying Party, then such defense or settlement will be subject to the reasonable approval of the Indemnified Party. Nothing herein shall prevent an Indemnified Party from retaining its own legal counsel and other consultants and participating in its own defense at its own cost and expense.

7.5 Release and Indemnification Regarding Liens. TranServ hereby releases and/or waives for itself and its successors in interest, and for all TranServ Designees and their successors in interest, any and all claims or right of mechanics or any other type of lien to assert and/or file upon Company's or any other party's property or any part thereof as a result of performing ITO Services. TranServ shall execute and deliver to Company such documents as may be required by applicable laws (*i.e.*, partial and/or final waivers of liens and/or affidavits of indemnification) to make this release effective and shall give all required notices to TranServ Designees with respect to ensuring the effectiveness of the foregoing releases against those parties. TranServ shall secure the removal of any lien that TranServ has agreed to release in this Section 7.5 within five (5) working days of receipt of written notice from Company to remove such lien. If not timely removed, Company may remove the lien and charge all costs and expenses including legal fees (for inside and/or outside legal counsel) to TranServ including, without limitation, the costs of bonding off such lien. Company, in its sole discretion, expressly reserves the right to off-set and/or retain any reasonable amount due to TranServ from payment of any one or more of TranServ's invoices upon Company having actual knowledge of any threatened and/or filed liens and/or encumbrances that may be asserted and/or filed by any TranServ Designee and/or third party with respect to the ITO Services, with final payment being made by Company only upon verification that such threatened and/or filed liens and/or encumbrances have been irrevocably satisfied, settled, resolved and/or released (as applicable), and/or that any known payment disputes concerning the ITO Services involving TranServ and any TranServ Designees have been resolved so that no actions, liens and/or encumbrances of any kind or nature will be filed against Company and/or Company's property.

7.6 Limitation of Liability. Other than as provided in Section 7.3, neither Party shall be liable to the other for any special, punitive, or consequential damages arising out of ITO Services, even if advised of the possibility of such damages. Company agrees that ITO Services are not consumer goods for purposes of international, U.S. Federal or U.S. state warranty laws. Indemnification pursuant to Sections 7.1, 7.2, and 7.3, as well as any direct damages to Company arising out of a material breach of this Agreement shall be limited in the aggregate to the total amount of fees actually paid by Company to TranServ under this Agreement through the date that any penalty or judgment is assessed.

Section 8 - Contract Managers; Dispute Resolution

8.1 Company Contract Manager. Company shall appoint an individual (the "Company Contract Manager") who shall serve as the primary Company representative under this

Agreement. The Company Contract Manager shall (a) have overall responsibility for managing and coordinating the performance of Company's obligations under this Agreement, and (b) be authorized to act for and on behalf of Company with respect to all matters relating to this Agreement. Notwithstanding the foregoing, the Company Contract Manager may, upon written notice to TranServ, delegate such of his or her responsibilities to other Company employees, as the Company Contract Manager deems appropriate.

8.2 TranServ Project Manager. TranServ shall appoint, among TranServ Personnel, an individual (the "TranServ Project Manager") who shall serve as the primary TranServ representative under this Agreement. The TranServ Project Manager shall have overall responsibility for managing and coordinating the performance of TranServ obligations under this Agreement. Notwithstanding the foregoing, the TranServ Project Manager may, upon written notice to Company, delegate such of his or her responsibilities to other TranServ Personnel, as the TranServ Project Manager deems appropriate.

8.3 Resolution of Disputes. Any dispute, claim or controversy between the Parties arising out of or relating to this Agreement (each, a "Dispute") shall be resolved in accordance with the procedures set forth in this Section 8.3; provided, however, that this Section 8.3 shall not apply to Disputes arising from or relating to (a) the amount of compensation to be paid by Company pursuant to Section 3.1, which shall be resolved pursuant to Section 3.6, (b) confidentiality or intellectual property rights, in which case either Party shall be free to seek available legal or equitable remedies, or (c) alleged violations of the OATT, in which case either Party shall be free to bring the Dispute to FERC.

8.3.1 Notice of Dispute. Each Party shall provide written notice to the other party of any Dispute, including a description of the nature of the Dispute.

8.3.2 Dispute Resolution by Contract Managers. Any Dispute shall first be referred to the Company Contract Manager and TranServ Project Manager, who shall negotiate in good faith to resolve the Dispute.

8.3.3 Dispute Resolution by Executive Management Representatives. If the Dispute is not resolved within fifteen (15) calendar days of being referred to the Company Contract Manager and the TranServ Project Manager pursuant to Section 8.3.2, then each Party shall have five (5) calendar days to appoint an executive management representative who shall negotiate in good faith to resolve the Dispute.

8.3.4 Binding Arbitration. If the Dispute is not resolved within ten (10) calendar days of being referred to executive management representatives, and the amount in dispute or potential damages exceeds $250,000 USD, the Parties shall proceed in good faith to submit immediately the matter to binding arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("AAA") as they may be amended from time to time (the "Arbitration Rules") subject to the following conditions:

(a) The Parties shall give due consideration to using the Expedited Procedures under the Arbitration Rules in any case in which no disclosed claim or counterclaim exceeds $75,000, exclusive of interest and arbitration fees and costs.

(b) The Parties agree that three arbitrators will be used. Each Party will directly appoint one arbitrator of its choosing from a list of members from the National Roster (as that term is used in the Arbitration Rules) provided by the AAA pursuant to R-12, within ten (10) Days after receipt of such names. The two arbitrators so appointed shall select a third arbitrator from the National Roster to serve as chairperson.

(c) "Baseball" arbitration (in which each Party presents a proposed award or resolution and the actual award must be one of the two submitted), or close variants thereof, shall not be used.

(d) The arbitrators have no authority to appoint or retain expert witnesses for any purpose unless agreed to by the Parties.

(e) All arbitration fees and costs shall be borne equally, regardless of which Party prevails.

(f) Each Party shall bear its own costs of legal representation and witness expenses, unless the arbitrator(s) determines that one Party should bear some or all of the costs of legal representation and witness expenses of the other Party.

(g) The Parties waive any right of appeal or recourse to any court except to compel arbitration, to compel the appointment of arbitrators, to stay judicial proceedings pending arbitration, for an injunction pending determination by the arbitrators, for disqualification of arbitrators, for aid in furtherance of arbitration, to confirm the award, to enforce any judgment confirming the award, or in circumstances of fraud or failure to disclose information or documents required by the arbitrators.

(h) The decision or award of a majority of the arbitrators shall govern. The decision or award of the arbitrators shall be final and binding upon the Parties to the same extent and to the same degree as if the matter had been adjudicated by a court of competent jurisdiction and shall be enforceable under the Federal Arbitration Act and applicable states' laws.

8.3.5 Rights and Remedies. If the Dispute is not resolved within ten (10) calendar days of being referred to executive management representatives, and the amount in dispute or potential damages does not exceed $250,000 USD, each Party is free to pursue any rights or remedies it may have at law or equity.

8.4 Rights Under FPA Unaffected. Except as provided in Section 17.2 relating to the variation or amendment of this Agreement, nothing in this Agreement is intended to limit or abridge any rights that Company may have to file or make application before FERC under Section 205 of the Federal Power Act to revise any rates, terms or conditions of the OATT.

8.5 Statute of Limitations; Continued Performance. The Parties agree to waive the applicable statute of limitations during the period of time that the Parties are seeking to resolve a Dispute pursuant to Section 8.3, and the statute of limitations shall be tolled for such period. The Parties shall continue to perform their obligations under this Agreement during the resolution of a Dispute.

Section 9 - Insurance

9.1 TranServ's Insurance Obligation. During the Term, TranServ shall provide and maintain, and shall require TranServ Designees to provide and maintain, the following insurance (and, except with regard to Workers' Compensation, naming Company as additional insured and waiving rights of subrogation against Company and Company's insurance carrier(s)), and TranServ shall submit evidence of such coverage(s) of TranServ and any TranServ Designees to Company prior to the start of ITO Services. Furthermore, TranServ shall notify Company, prior to the commencement of ITO Services, of any threatened, pending and/or paid off claims to third parties, individually or in the aggregate, which otherwise affects the availability of the limits of such coverage(s) inuring to the benefit of Company as hereinafter specified:

9.1.1 Workers' Compensation and Employer's Liability Policy, which shall include provisions required by applicable law in the jurisdiction of location of workers.

9.1.2 Employer's Liability (Coverage B) with limits of One Million Dollars ($1,000,000) Bodily Injury by Accident, each Accident, $1,000,000 Bodily Injury by Disease, each Employee, and including:

(a) a thirty (30) day cancellation clause; and

(b) broad form all states endorsement.

9.1.3 Commercial General Liability Policy, which shall have minimum limits of One Million Dollars ($1,000,000) each occurrence; One Million Dollars ($1,000,000) Products/Completed Operations Aggregate each occurrence; One Million Dollars ($1,000,000) Personal and Advertising Injury each occurrence, in all cases subject to Two Million Dollars ($2,000,000) in the General Aggregate for all such claims, and including:

(a) a thirty (30) day cancellation clause;

(b) Blanket Written Contractual Liability to the extent covered by the policy against liability assumed by TranServ under this Agreement; and

(c) Broad Form Property Damage.

9.1.4 Commercial Automobile Liability Insurance covering the use of all owned, non-owned, and hired automobiles, with a bodily injury, including death, and property damage combined single minimum limit of One Million Dollars ($1,000,000) each occurrence with respect to TranServ's vehicles assigned to or used in performance of ITO Services under this Agreement.

9.1.5 Umbrella/Excess Liability Insurance with minimum limits of Two Million Dollars ($2,000,000) per occurrence; Two Million Dollars ($2,000,000) aggregate, to apply to employer's liability, commercial general liability, and automobile liability.

9.1.6 To the extent applicable, if engineering or other professional services will be separately provided by TranServ as specified in Appendix A, then Professional Liability Insurance with limits of Three Million Dollars ($3,000,000) per occurrence and Three Million Dollars ($3,000,000) in the aggregate, which insurance shall be either on an occurrence basis or on a claims made basis (with a retroactive date satisfactory to Company).

9.2 Quality of Insurance Coverage. The above policies to be provided by TranServ shall be written by insurance companies which are both licensed to do business in the state where ITO Services will be performed and either satisfactory to Company or having a Best Rating of not less than "A-". These policies shall not be materially changed or canceled except with thirty (30) days written notice to Company from TranServ and the insurance carrier. Evidence of coverage, notification of cancellation or other changes shall be mailed to: Attention: Manager, Supply Chain, LG&E and KU Services Company, P.O. Box 32020, Louisville, Kentucky 40232.

9.3 Implication of Insurance. Company reserves the right to request and receive a summary of coverage of any of the above policies or endorsements; however, Company shall not be obligated to review any of TranServ's certificates of insurance, insurance policies, or endorsements, or to advise TranServ of any deficiencies in such documents. Any receipt of such documents or their review by Company shall not relieve TranServ from or be deemed a waiver of Company's rights to insist on strict fulfillment of TranServ's obligations under this Agreement.

9.4 Other Notices. TranServ shall provide written notice of any accidents or claims in connection with ITO Services or this Agreement to Company's Manager, Risk Management at LG&E and KU Services Company, P.O. Box 32030, Louisville, Kentucky 40232.

Section 10 - Confidentiality

10.1 Definition of Confidential Information. For purposes of this Agreement, "Confidential Information" shall mean, in respect of each Party, all information and documentation of such Party, whether disclosed to or accessed by the other Party in connection with this Agreement and which is identified as Confidential Information, or which otherwise would be treated as confidential by the recipient, including confidential information provided by third-parties; provided, however, that the term "Confidential Information" shall not include information that: (a) is independently developed by the recipient, as demonstrated by the recipient's written records, without violating the disclosing Party's proprietary rights; (b) is or becomes publicly known (other than through unauthorized disclosure); (c) is disclosed by the owner of such information to a third party free of any obligation of confidentiality; (d) is already known by the recipient at the time of disclosure, as demonstrated by the recipient's written records, and the recipient has no obligation of confidentiality other than pursuant to this Agreement or any confidentiality agreements between the Parties entered into before the Commencement Date; or (e) is rightfully received by a Party free of any obligation of confidentiality.

10.2 Protection of Confidential Information. All Confidential Information shall be held in confidence by the recipient to the same extent and in at least the same manner as the recipient protects its own Confidential Information, and such Confidential Information shall be used only for purposes of performing obligations under this Agreement. Except as otherwise provided in

Section 10.3, neither Party shall disclose, publish, release, transfer or otherwise make available Confidential Information of, or obtained from, the other Party in any form to, or for the use or benefit of, any person or entity without the owner of such information's prior written consent. Each Party shall be permitted to disclose relevant aspects of the other Party's Confidential Information to its officers, directors, agents, professional advisors, contractors, subcontractors (including TranServ Designees) and employees and to the officers, directors, agents, professional advisors, contractors, subcontractors and employees of its Affiliates (collectively, "Representatives"), to the extent that such disclosure is reasonably necessary for the performance of its duties and obligations or the determination, preservation or exercise of its rights and remedies under this Agreement; provided, however, that the recipient shall take all reasonable measures to ensure that Confidential Information is not disclosed or duplicated in contravention of the provisions of this Agreement by such officers, directors, agents, professional advisors, contractors, subcontractors and employees. Recipient agrees to be liable for the wrongful actions of its Representatives under this Section 10.2. The obligations in this Section 10 shall not restrict any disclosure pursuant to any Regulatory Authority if such release is necessary to comply with valid laws, governmental regulations or final orders of regulatory bodies or courts; provided that, other than in respect of disclosures pursuant to Section 10.3, the recipient shall give prompt written notice to the disclosing Party in reasonable time to exercise whatever legal rights the disclosing Party may have to prevent or limit such disclosure. Further, the recipient shall cooperate with the disclosing Party in preventing or limiting such disclosure.

10.3 Regulatory Requests for Confidential Information. Notwithstanding anything in this Section 10 to the contrary, if a Regulatory Authority or its staff, during the course of an investigation or otherwise, requests Confidential Information from TranServ, TranServ shall provide the requested Confidential Information to the requesting Regulatory Authority or its staff within the time provided for in the request for information. In providing the Confidential Information to a Regulatory Authority or its staff, TranServ shall, consistent with 18 C.F.R. § 388.112 (2011) or any other applicable confidentiality regulation, request that the Confidential Information be treated as confidential and non-public by the Regulatory Authority and its staff and that the information be withheld from public disclosure. TranServ shall notify Company when it is notified by the Regulatory Authority or its staff that a request for public disclosure of, or decision to publicly disclose, Confidential Information has been received, at which time either TranServ or Company may respond before such Confidential Information is made public, pursuant to 18 C.F.R. § 388.112 or the applicable confidentiality regulation.

Section 11 - Force Majeure.

11.1 Force Majeure. Neither Party shall be liable to the other Party for any failure or delay of performance hereunder due to an event which (i) is not reasonably foreseeable or within the reasonable control of the Party claiming Force Majeure (the "Claiming Party") or any Person over which the Claiming Party has control, (ii) was not caused by the acts, omissions, negligence, fault or delays of the Claiming Party or any person over whom the Claiming Party has control, (iii) is not an act, event or condition the risks or consequences of which the Claiming Party has expressly agreed to assume pursuant to this Agreement, and (iv) by the prompt exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided (collectively, (i) - (iv) are "Force Majeure"). Force Majeure shall include: acts of God; acts of the public enemy, war, hostilities, invasion, insurrection, riot, civil disturbance, or order of any competent civil or military government; explosion or fire; strikes or lockouts or other industrial action (excluding those of the Claiming Party unless such action is part of a wider industrial dispute materially affecting other employers); labor or material shortage; malicious acts, vandalism or sabotage; action or restraint by court order of any public or governmental authority (so long as the Claiming Party has not applied for or assisted in the application for, and has opposed where and to the extent reasonable, such government action). Neither Party shall be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to Force Majeure, except for the obligation to pay any amount when due, provided that the Claiming Party:

11.1.1 gives prompt written notice to the other Party of the event or circumstance giving rise to the event of Force Majeure;

11.1.2 affords the other Party reasonable access to information about the event or circumstances giving rise to the event of Force Majeure;

11.1.3 takes commercially reasonable steps to restore its ability to perform its obligations hereunder as soon as reasonably practicable, provided that the Claiming Party shall not be obligated to take any steps that are not otherwise in accordance with Good Utility Practice; and

11.1.4 exercises commercially reasonable efforts to perform its obligations hereunder.

Section 12 - Reporting; Audit.

12.1 Regulatory Reporting.

12.1.1 TranServ shall have the authority to report in writing to FERC in respect of any compensation-related Dispute that arises between TranServ and Company pursuant to Section 3.6.

12.1.2 TranServ shall report in writing to FERC every six (6) months (commencing on the six (6) month anniversary of the Commencement Date and every six (6) months thereafter during the Term) in respect of (a) any concerns expressed by stakeholders and TranServ's response to same and (b) any issues or OATT provisions that hinder TranServ from performing its duties and obligations under this Agreement and the OATT.

12.1.3 In addition to the reports provided for above, TranServ shall make such other reports to Regulatory Authorities as may be required by applicable law and regulations or as may be requested by such Regulatory Authorities.

12.2 Books and Records. TranServ shall maintain full and accurate books and records pertinent to this Agreement, and TranServ shall maintain such books and records for a minimum of five (5) years following the expiration or early termination of this Agreement or longer if necessary to resolve a pending Dispute. Company will have the right, at reasonable times and under reasonable conditions, to inspect and audit, or have an independent third party inspect and audit, TranServ's operations, books, and records (a) to ensure compliance with this Agreement, including TranServ's performance of ITO Services in accordance with Section 1.3.1, (b) to verify any cost claims or other amounts due hereunder, and (c) to validate TranServ's internal controls with respect to the performance of ITO Services. TranServ shall maintain an audit trail, including all original transaction records and timekeeping records, of all financial and non-financial transactions and activities resulting from or arising in connection with this Agreement as may be necessary to enable Company or the independent third party, as applicable, to perform the foregoing activities. Company shall be responsible for any costs and expenses incurred in connection with any such inspection or audit, unless such inspection or audit discovers that Company was charged inappropriate or incorrect costs and expenses, in which case, TranServ shall be responsible for a percentage of the costs and expenses incurred in connection with such inspection or audit equal to the percentage variance by which Company was charged inappropriate or incorrect costs and expenses. TranServ shall provide reasonable assistance necessary to enable Company or an independent third party, as applicable, to perform the foregoing activities and shall not be entitled to charge Company for any such assistance. Amounts incorrectly or inappropriately invoiced by TranServ to Company, whether discovered prior to or subsequent to payment by Company, shall be adjusted or reimbursed to Company by TranServ within twenty (20) days of notification by Company to TranServ of the error in the invoice.

Section 13 - Independent Contractor

13.1 TranServ, in performing ITO Services, shall not act as an agent or employee of Company, but shall be and act as an independent contractor and, except as established in Section 1.3.1, shall be free to perform ITO Services by such methods and in such manner as TranServ may choose, doing everything necessary to perform such ITO Services properly and safely and having supervision over and responsibility for the safety and actions of its employees and the suitability of its equipment. TranServ Personnel and TranServ Designees shall not be deemed to be employees and/or agents of Company. TranServ agrees that if any portion of ITO Services are subcontracted to TranServ Designees, such TranServ Designees shall be bound by and observe the conditions of this Agreement to the same extent as required of TranServ. In such event, Company strongly encourages the use of Minority Business Enterprises, Women Business Enterprises and Disadvantaged Business Enterprises, as defined under federal law and as certified by a certifying agency that Company recognizes as proper.

13.2 Notwithstanding any provision in this Agreement to the contrary, unless approved in writing by Company, TranServ shall not (and shall not permit any TranServ Personnel or TranServ Designee to):

13.2.1 Sell, lease, pledge, mortgage, encumber, convey, or make any license, exchange or other transfer, assignment or disposition of any property or assets of Company;

13.2.2 Enter into, amend, terminate, modify or supplement any contract or agreement (including any labor or collective bargaining agreement) on behalf, or in the name, of Company;

13.2.3 Except upon the approval of Company or pursuant to the direction of Company, take any action that would, to TranServ's knowledge: (a) invalidate any warranty that runs to Company under any contract or agreement; or (b) release any person or entity from its obligations under any contract or agreement with Company;

13.2.4 Make any warranty or representation on behalf of Company;

13.2.5 Except as contemplated under Section 7.4, settle, compromise, assign, pledge, transfer, release or consent to the compromise, assignment, pledge, transfer or release of any claim, suit, debt, demand or judgment against or due by Company, or submit any such claim, dispute or controversy to arbitration or judicial process, or stipulate in respect thereof to a judgment, or consent to the same;

13.2.6 Pledge the credit of Company in any way in respect of any commitments for which it has not received express written authorization from Company; or

13.2.7 Engage in any other transaction on behalf of Company not permitted under this Agreement.

Section 14 - Taxes.

Each Party shall be responsible for the payment of its own taxes, including taxes based on its net income, employment taxes of its employees, taxes on any property it owns or leases, and sales, use, gross receipts, excise, value-added or other transaction taxes. Sales and/or use taxes, that become applicable to services performed within Minnesota, shall be added to TranServ fees and compensation otherwise herein described.

Section 15 - Notices.

15.1 Notices. All notices, requests, consents and other communications required or permitted hereunder shall be in writing, signed by the Party giving such notice or communication, and shall be deemed given: (a) upon receipt, when mailed by U.S. certified mail, postage prepaid, return receipt requested; or (b) upon the next business day, when sent by overnight delivery, postage prepaid using a recognized courier service.

If to Company:

LG&E/KU
VP, Transmission
220 West Main St
PO Box 32010
Louisville, KY 40232

If to TranServ:

TranServ International, Inc.
Contracts Administration
3660 Technology Drive NE
Minneapolis, MN 55418

15.2 Changes. Either Party may, from time to time, change the names, addresses, facsimile numbers or other notice information set out in Section 15.1 by notice to the other Party in accordance with the requirements of Section 15.1.

Section 16 - Personnel and Work Conditions; NERC Requirements.

16.1 Applicable Laws and Safety. TranServ agrees to protect TranServ Personnel and TranServ Designees and be responsible for their performance of the ITO Services, and to protect Company's facilities, property, employees and third parties from damage or injury. TranServ shall at all times be solely responsible for complying with any and all applicable laws and facility rules relating to health and safety, in connection with ITO Services and for obtaining (but only as approved by Company) all permits and approvals necessary to perform ITO Services. Without limiting the foregoing, TranServ agrees to strictly abide by and observe all standards of the Occupational Safety & Health Administration ("OSHA") which are applicable to ITO Services, as well as Company's Contractor Code of Business Conduct and Company's Contractor/Subcontractor Safety Policy which are both hereby incorporated by reference (Contractor hereby acknowledges receipt of a copy of such Company's Contractor Code of Business Conduct and Company's Contractor/Subcontractor Safety Policy) and any other rules and regulations of the Company, all of which are provided to TranServ in writing and incorporated herein by reference. TranServ also agrees to review in good faith and execute any amendments and/or modifications that may be issued in the future by Company from time to time, with respect to Company's Contractor Code of Business Conduct and/or any of its related policies which are the subject of this Section 16, provided however, that TranServ shall not be obliged by such requirement if the requirements conflicts with an alternate regulatory code of conduct imposed on TranServ. In the event TranServ subcontracts any of ITO Services to a TranServ Designee, TranServ shall notify Company in writing of the identity of TranServ Designee before utilizing TranServ Designee. TranServ shall require any TranServ Designees to complete the safety and health questionnaire and checklists provided by Company and shall provide a copy of such documents to Company upon request. TranServ shall conduct, and require such TranServ Designees to conduct, safety audits and job briefings during performance of ITO Services as applicable. In the event such TranServ Designee has no procedure for conducting safety audits and job briefings, TranServ shall include TranServ Designee in its safety audits and job briefings. All applicable safety audits shall be documented in writing by TranServ and such TranServ Designees. TranServ shall provide documentation of any and all audits identifying safety deficiencies and concerns and corrective action taken as a result of such audits to Company semi-monthly. TranServ further specifically acknowledges, agrees and warrants that TranServ has complied, and shall at all times during the term of this Agreement, comply in all respects with all laws, rules and regulations relating to the employment authorization of TranServ Personnel including, but not limited to, the Immigration Reform and Control Act of 1986, as amended, and the Illegal Immigration Reform and Immigrant Responsibility Act of 1996, as amended, whereby TranServ certifies to Company that TranServ has (a) properly maintained, and shall at all times during the term of this Agreement properly maintain all records required by Immigration and Customs Enforcement, such as the completion and maintenance of the Form I-9 for each TranServ employee; (b) that TranServ maintains and follows an established policy to verify the employment authorization of TranServ Personnel; (c) that TranServ has verified the identity and employment eligibility of all TranServ Personnel in compliance with all applicable laws; and (d) that TranServ is without knowledge of any fact that would render any TranServ Personnel or TranServ Designee ineligible to legally work in the United States. TranServ further acknowledges, agrees and warrants that any TranServ Designee shall be required to agree to these same terms as a condition to being awarded any subcontract for such ITO Services.

16.2 Hazards and Training. TranServ shall furnish adequate numbers of trained, qualified, and experienced TranServ Personnel suitable for performance of ITO Services. Such TranServ Personnel shall be skilled and properly trained to perform ITO Services and recognize all hazards associated with ITO Services. Without limiting the foregoing, TranServ shall participate in any safety orientation or other of Company's familiarization initiatives related to safety and shall strictly comply with any monitoring initiatives as determined by Company.

16.3 Drug and Alcohol. TranServ shall develop and strictly comply with any and all drug and alcohol testing requirements as required by applicable laws. TranServ shall provide Company with a copy of its drug and alcohol testing requirements.

16.4 NERC Reliability Standards. The following additional provisions shall apply to the extent TranServ's performance of ITO Services requires physical or electronic access to areas or assets which are located within physical security perimeters as defined by NERC's Reliability Standards for the Bulk Electric Systems of North America (collectively, the "NERC Standards"), including without limitation any Company data center or control center. In the event of TranServ's non-compliance with the NERC Standards referenced in this Section 16.4, Company shall notify TranServ in writing of the non-compliance and specify appropriate remedial actions.

16.4.1 Information Protection. Without compromising the confidentiality provisions in Section 10, TranServ shall at all times comply with the Company's information protection program(s) as defined by CIP-003, R4. Among the information protected by this program are: (i) all operational procedures; (ii) lists of critical cyber assets; (iii) network topology or similar diagrams; (iv) floor plans of computing centers that contain critical cyber assets; (v) equipment layouts of critical cyber assets; (vi) disaster recovery plans; (vii) incident response plans; and (viii) security configuration information. TranServ shall protect this protected information from disclosure consistent with the program.

16.4.2 Access Revocation. TranServ shall immediately advise appropriate Company's management if any TranServ Personnel or TranServ Designees who have key card access to a Company restricted area or electronic access to a protected system no longer require such access.

16.4.3 Training. If any TranServ Personnel require key card access to a Company restricted area or electronic access to a protected system, TranServ shall ensure that such personnel complete, and retake as requested, all necessary NERC training as requested by Company.

16.4.4 Personnel Risk Assessment. If any TranServ Personnel require key card access to a Company restricted area or electronic access to a protected system, TranServ shall ensure that Company receives necessary waivers and information from TranServ Personnel to complete, and repeat as necessary, such background checks as requested by Company.

16.4.5 Continuing Obligations. TranServ further acknowledges that its compliance with the NERC Standards referenced in this Section 16.4 is a continuing obligation during and after the Term. Upon written notice to TranServ, Company shall have the absolute right to audit and inspect any and all information regarding TranServ's compliance with this Section 16.4, and/or to require confirmation of the destruction of any documentation received from or regarding Company. TranServ is encouraged to contact Company's Compliance Department pursuant to Section 16.5 to ensure TranServ understands and complies with this Section 16.4.

16.5 Compliance Department. The Company has a Compliance Department. Should TranServ have actual knowledge of violations of any of the herein stated policies of conduct in this Section 16, or in standards of performance detailed in Section 1.3.1, or have a reasonable basis to believe that such violations have occurred, whether by TranServ Personnel or a TranServ Designee, TranServ has an affirmative obligation to immediately report, at least on an anonymous basis, any such known violations to the Company's Office of Compliance in care of Director, Compliance and Ethics, LG&E/KU Services, 220 West Main Street, Louisville, Kentucky 40202.

16.6 Equal Employment Opportunity. To the extent applicable, TranServ shall comply with all of the following provisions, which are incorporated herein by reference: (i) Equal Opportunity regulations set forth in 41 C.F.R. § 60-1.4(a) and (c), prohibiting employment discrimination against any employee or applicant because of race, color, religion, sex, or national origin; (ii) Vietnam Era Veterans Readjustment Assistance Act regulations set forth in 41 C.F.R. § 60-250.4 relating to the employment and advancement of disabled veterans and Vietnam era veterans; (iii) Rehabilitation Act regulations set forth in 41 C.F.R. § 60-741.4 relating to the employment and advancement of qualified disabled employees and applicants for employment; (iv) the clause known as "Utilization of Small Business Concerns and Small Business Concerns Owned and Controlled by Socially and Economically Disadvantaged Individuals" set forth in 15 USC § 637(d)(3); and (v) the subcontracting plan requirement set forth in 15 USC § 637(d).

Section 17 - Miscellaneous Provisions.

17.1 Governing Law. This Agreement and the rights and obligations of the Parties hereunder shall be governed by and construed in accordance with the laws of the Commonwealth of Kentucky, without giving effect to its conflicts of law rules.

17.2 Amendment. This Agreement shall not be varied or amended unless such variation or amendment is agreed to by the Parties in writing and accepted by applicable Regulatory Authorities. The Parties explicitly agree that neither Party shall unilaterally petition to FERC pursuant to the provisions of Sections 205 or 206 of the Federal Power Act to amend this Agreement or to request that FERC initiate its own proceeding to amend this Agreement.

Nothing in this Section 17.2 shall be construed to limit or affect any other rights that the Parties may have as set forth in Section 8.4, the OATT or otherwise.

17.3 Liability of Affiliates. Any and all liabilities of Company and/or its Affiliates under this Agreement shall be several but not joint.

17.4 Publicity. TranServ shall not issue news releases, publicize or issue advertising pertaining to ITO Services or this Agreement without first obtaining the written approval of Company.

17.5 Assignment. Any assignment of this Agreement or any interest herein or delegation of all or any portion of a Party's obligations, by operation of law or otherwise, by either Party without the other Party's prior written consent shall be void and of no effect; provided, however, that consent will not be required for Company to assign this Agreement to an Affiliate or a successor entity that acquires all or substantially all of the operational business assets of the assigning entity whether by merger, consolidation, reorganization, sale, spin-off or foreclosure; provided, further, that such Affiliate or successor entity (a) agrees to assume all obligations hereunder from and after the date of such assignment and (b) has the legal authority and operational ability to satisfy the obligations under this Agreement. As a condition to the effectiveness of such assignment (i) the assignor shall promptly notify the other Party of such assignment, (ii) the Affiliate or successor entity shall provide a confirmation to the other Party of its assumption of assignor's obligations hereunder, and (iii) assignor shall promptly reimburse the other Party, upon receipt of an invoice, for any one-time incremental costs reasonably incurred as a result of such assignment. For the avoidance of doubt, nothing herein shall preclude Company from transferring any or all of its transmission facilities to another entity or disposing of or acquiring any other transmission assets. Notwithstanding anything to the contrary contained in this Section 17.5, TranServ shall be entitled to contract with one or more persons (each, an "TranServ Designee") to perform only those ITO Services which the OATT expressly provides for being performed by a "designee" of TranServ (as opposed to TranServ or TranServ Personnel), provided that TranServ shall not be relieved of any of its obligations, responsibilities or liabilities under this Agreement as a result of contracting with one or more TranServ Designees in accordance with this Section 17.5 and shall be responsible and liable for any ITO Services performed by TranServ Designees.

17.6 No Third Party Beneficiaries. Except as otherwise expressly provided in this Agreement, this Agreement is made solely for the benefit of the Parties and their successors and permitted assigns and no other person shall have any rights, interest or claims hereunder or otherwise be entitled to any benefits under or on account of this Agreement as third party beneficiary or otherwise.

17.7 Waivers. No waiver of any provision of this Agreement shall be effective unless it is signed by the Party against which it is sought to be enforced. The delay or failure by either Party to exercise or enforce any of its rights or remedies under this Agreement shall not constitute or be deemed a waiver of that Party's right thereafter to enforce those rights or remedies, nor shall any single or partial exercise of any such right or remedy preclude any other or further exercise thereof or the exercise of any other right or remedy.

17.8 Enforcement of Rights. Each Party shall have the right to recover from the other Party all expenses, including fees for and expenses of inside and/or outside counsel, arising out of the other Party's breach of this Agreement or any other action to enforce or defend rights hereunder.

17.9 Severability; Renegotiation. The invalidity or unenforceability of any portion or provision of this Agreement shall in no way affect the validity or enforceability of any other portion or provision herein. If any provision of this Agreement is found to be invalid, illegal or otherwise unenforceable, the same shall not affect the other provisions hereof or the whole of this Agreement and shall not render invalid, illegal or unenforceable this Agreement or any of the remaining provisions of this Agreement. If any provision of this Agreement or the application thereof to any person, entity or circumstance is held by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, or if a modification or condition to this Agreement is imposed by such court or regulatory authority, the Parties shall in good faith negotiate such amendment or amendments to this Agreement as will restore the relative benefits and obligations of the Parties immediately prior to such holding, modification or condition.

17.10 Remedies. No remedy conferred by any of the provisions of this Agreement is intended to be exclusive of any other remedy available at law or equity or otherwise. The election of one or more remedies shall not constitute a waiver of the right to pursue any other available remedies.

17.11 Representations and Warranties. Each Party represents and warrants to the other Party as of the date hereof as follows:

17.11.1 Organization. It is duly organized, validly existing and in good standing under the laws of the State in which it was organized, and has all the requisite power and authority to own and operate its material assets and properties and to carry on its business as now being conducted and as proposed to be conducted under this Agreement.

17.11.2 Authority. It has the requisite power and authority to execute and deliver this Agreement and, subject to the procurement of applicable regulatory approvals, to perform its obligations under this Agreement. The execution and delivery of this Agreement by it and the performance of its obligations under this Agreement have been duly authorized by all necessary corporate action required on its part.

17.11.3 Binding Effect. Assuming the due authorization, execution and delivery of this Agreement by the other Party, this Agreement constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency or other similar applicable laws affecting creditors' rights generally, and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

17.11.4 Regulatory Approval. It has obtained or will obtain by the Commencement Date, any and all approvals of, and acceptances for filing by, and has given or will give any notices to, any applicable federal or state authority, including FERC and the KPSC (as applicable), that are required for it to execute, deliver, and perform its obligations under this Agreement.

17.11.5 No Litigation. There are no actions at law, suits in equity, proceedings, or claims pending or, to its knowledge, threatened against it before or by any federal, state, foreign or local court, tribunal, or governmental agency or authority that might materially delay, prevent, or hinder the performance by such entity of its obligations hereunder.

17.11.6 No Violation or Breach. The execution, delivery and performance by it of its obligations under this Agreement do not and shall not: (a) violate its organizational documents; (b) violate any applicable law, statute, order, rule, regulation or judgment promulgated or entered by any applicable federal or state authority, which violation could reasonably be expected to materially adversely affect the performance of its obligations under this Agreement; or (c) result in a breach of or constitute a default of any material agreement to which it is a party.

17.11.7 No Other Warranties. EXCEPT AS PROVIDED IN THIS AGREEMENT, TRANSERV MAKES NO OTHER WARRANTIES OF ANY KIND, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE.

17.12 Further Assurances. Each Party agrees that it shall execute and deliver such further instruments, provide all information, and take or forbear such further acts and things as may be reasonably required or useful to carry out the purpose of this Agreement and are not inconsistent with the provisions of this Agreement.

17.13 Entire Agreement. This Agreement and the Attachments hereto set forth the entire agreement between the Parties with respect to the subject matter hereof, and supersede all prior agreements, whether oral or written, related to the subject matter of this Agreement. The terms of this Agreement and the Attachments hereto are controlling, and no parole or extrinsic evidence, including to prior drafts and drafts exchanged with any third parties, shall be used to vary, contradict or interpret the express terms and conditions of this Agreement.

17.14 Good Faith Efforts. Each Party agrees that it shall in good faith take all reasonable actions necessary to permit it and the other Party to fulfill their obligations under this Agreement. Where the consent, agreement or approval of any Party must be obtained hereunder, such consent, agreement or approval shall not be unreasonably withheld, delayed or conditioned. Where a Party is required or permitted to act, or omit to act, based on its opinion or judgment, such opinion or judgment shall not be unreasonably exercised, other than where expressly provided for herein. To the extent that the jurisdiction of any federal or state authority applies to any part of this Agreement or the transactions or actions covered by this Agreement, each Party shall cooperate with the other Party to secure any necessary or desirable approval or acceptance of such authorities of such part of this Agreement or such transactions or actions.

17.15 Time of the Essence. With respect to all duties, obligations and rights of the Parties specified by Regulatory Authorities, time shall be of the essence in this Agreement.

17.16 Interpretation. Unless the context of this Agreement otherwise clearly requires:

17.16.1 all defined terms in the singular shall have the same meaning when used in the plural and vice versa;

17.16.2 the terms “hereof,” “herein,” “hereto” and similar words refer to this entire Agreement and not to any particular Section, Attachment or any other subdivision of this Agreement;

17.16.3 references to “Section” or “Appendix” refer to this Agreement, unless specified otherwise;

17.16.4 references to any law, statute, rule, regulation, notification or statutory provision shall be construed as a reference to the same as it applies to this Agreement and may have been, or may from time to time be, amended, modified or re-enacted;

17.16.5 references to “includes,” “including” and similar phrases shall mean “including, without limitation;”

17.16.6 the captions, section numbers and headings in this Agreement are included for convenience of reference only and shall not in any way affect the meaning or interpretation of this Agreement;

17.16.7 “or” may not be mutually exclusive, and can be construed to mean “and” where the context requires there to be a multiple rather than an alternative obligation; and

17.16.8 references to a particular entity include such entity’s successors and assigns to the extent not prohibited by this Agreement.

17.17 Joint Effort. Preparation of this Agreement has been a joint effort of the Parties and the resulting document shall not be construed more severely against one of the Parties than against the other and no provision in this Agreement is to be interpreted for or against any Party because that Party or its counsel drafted such provision. Each Party acknowledges that in executing this Agreement it has relied solely on its own judgment, belief and knowledge, and such advice as it may have received from its own counsel, and it has not been influenced by any representation or statement made by the other Party or its counsel not contained in this Agreement.

17.18 Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument, binding upon Company and TranServ, notwithstanding that Company and TranServ may not have executed the same counterpart.

The Parties have caused this Independent Transmission Organization Agreement to be executed by their duly authorized representatives as of the dates shown below.

LOUISVILLE GAS AND ELECTRIC COMPANY/
KENTUCKY UTILITIES COMPANY

/s/ Stephanie R. Pryor

____
Name: Stephanie R. Pryor
Title: Manager Supply Chain
Date: 12/9/2016

TRANSERV INTERNATIONAL, INC.

/s/ Sasan Mokhtari, PhD

____
Name: Sasan Mokhtari, PhD
Title: President & CEO
Date: 12/8/2016

Appendix A

Louisville Gas and Electric Company/

Kentucky Utilities Company

INDEPENDENT TRANSMISSION ORGANIZATION

SERVICE SPECIFICATION

TABLE OF CONTENTS

1. Overview

This Appendix A is intended to be consistent with the terms and conditions of the LG&E/KU Open Access Transmission Tariff (OATT), including Attachment P thereto. If there is any conflict between this Appendix A and the OATT, the OATT shall govern. TranServ shall perform its obligations under this Appendix A in accordance with Section 1.3.1 of this Agreement.

The services delegated to TranServ include the administration of the LG&E/KU Open Access Same-time Information System (OASIS), transmission service request evaluation process, Available Transfer Capability (ATC)/ Available Flowgate Capability (AFC) management, study queue administration, study performance, and stakeholder facilitation. TranServ, as the ITO, will administer the OATT granting of service for both short and long-term transmission requests, administer the large generator interconnection request queue, and perform transmission studies. TranServ will facilitate the LG&E/KU long-term transmission planning function and stakeholder processes.

2. Definitions

Company - Louisville Gas and Electric Company/Kentucky Utilities Company (LG&E/KU)

ITO - Independent Transmission Organization

ITO Services - The applicable functions to be performed as specified in the ITO Agreement

RC - Reliability Coordinator

Service Interruption - A Service Interruption is the loss of Service function, under the direct control of TRANSERV with no mutually agreed to work around provided within the Service

Normal Business Hours - TranServ normal business hours are between the hours of 0700 and 1700 CT, Monday-Friday on days other than the holidays listed below:

1. New Year's Day
2. Memorial Day
3. Independence Day
4. Labor Day
5. Thanksgiving
6. Day after Thanksgiving
7. Day before Christmas
8. Christmas Day

3. Roles and Responsibilities for Providing ITO Services

3.1 TranServ

TranServ International, Inc. (TranServ) will provide services to LG&E/KU as the ITO. The services that TranServ will provide include:

3.1.1 Customer Interface

Responsibility for operating and maintaining OASIS website and keeping it up-to-date with Federal Energy Regulatory Commission (FERC) and North American Energy Standards Board (NAESB) posting requirements, including all Order No. 890 posting requirements (such as study performance metrics, Available Transfer Capability (ATC) calculations, etc.). This includes establishing an interface for customers to submit service requests, and oversight and evaluation of ATC values calculated using software procured from Open Access Technology International, Inc. (OATI) and information from the RC. TranServ's responsibilities and duties in administering OASIS will include the following:

- Performing the duties of a Responsible Party as defined in the Commission's OASIS regulations, 18 C.F.R. § 37.5 and FERC Order No. 676.
- Posting information required to be on the Transmission Provider's OASIS under the Commission's OASIS regulations, 18 C.F.R. § 37.6 and FERC Order No. 676.
- Maintaining and retaining information posted on OASIS in accordance with the Commission's regulations, including 18 C.F.R. Parts 37 and 125.
- Establishing and maintaining queues for processing transmission service requests and generator interconnection (GI) requests.
- Participating in the drafting and posting of Business Practices on the OASIS website, including any FERC or NAESB-required Business Practices. Company shall have final review, ownership, and approval for all Business Practices.
- Participating in periodic reviews of, and providing expertise/comments on, the OATT. Company retains final authority over the OATT's content, including retaining the right and responsibility to file changes to the OATT.
- Participating in stakeholder meetings and/or conference calls as required. These

stakeholder meetings will include TranServ, Company, Customers (as appropriate) the RC, and other entities as required, to address concerns regarding Company's system, administration of the OATT, and related issues.

- Responsibility for coordinating with third-party transmission system owners and operators as necessary to support customer service requests. This includes coordinating the provision of any data from Company to the third-party system.
- Management of ATC/AFC Calculation and Posting.
- Implementation of certain aspects of the Congestion Management Process (CMP) established by the Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection LLC (PJM), and TVA.
- Administration of request evaluations for LG&E/KU tariff service.
- Processing of e-Tags as the transmission provider.
- Reviewing software changes requested from OATI, verifying and testing for proper operations before OATI implements those changes.

3.1.2 Transmission Service and Generator Interconnection Requests and Studies

- Receive and process all applications for Point-to-Point, Network Integration Transmission Service (NITS), and for GIs.
- For short-term Point-to-Point Transmission Service requests (i.e., where the request is within the posted ATC horizon), evaluate and approve a request where the posted ATC is sufficient for the requested transaction. If ATC is insufficient, TranServ shall propose conditional service options to the customer in accordance with the OATT, or otherwise deny the service. If the customer accepts conditional service options, TranServ will be responsible for performing biennial reassessments, as provided under the OATT.
- For long-term Point-to-Point Transmission Service requests, NITS, or GI requests:
    - Determine whether a System Impact Study (SIS) is necessary to accommodate the request.
    - Render all study agreements (SIS, Interconnection Feasibility Studies (IFS), Facilities Study (FS), and Feasibility Analysis Studies (FAS)) to customers within the timeframe provided in the OATT.

  - Perform the SIS or FAS in the timeframe provided in the OATT, including clustered SISs when requested by customers and/or Company.
  - Perform the SIS or FAS using Company's planning criteria.
  - For any study that TranServ performs that requires information from Company (e.g., good faith construction estimates that are included in the SIS), request such information from Company no less than ten (10) business days before the expiration of the applicable study period.
  - Complete study reports and post on OASIS within the timeframe required under the OATT.
  - Notify the Company and individual customers of completed study reports, and alert the Company to initiate service agreements, if applicable.
  - Receive customer deposits.
  - Bill customers for SIS, IFS, FS, and FAS as required by the OATT, including provision of an itemized bill for services if requested by a customer.
  - Reimburse Company for any study costs incurred in contributing to the study and render payment to any third-party vendors for work performed.
- Responsible for receiving and processing requests to designate or un-designate Network Resources, as provided under the OATT.
- If a customer requests a modification to its service, or if a customer assigns its transmission service to a third-party who request modification to the service, process those modification requests in accordance with the terms of the OATT.
- Track all study metrics, including data submittals, input validations, modifications, time and costs associated to perform the study.
- Track the performance of all studies and alert Company if a FERC filing requirement or penalty payment has been triggered due to late studies, as described under the OATT.

3.1.3 ATC Calculation

- Calculate ATC as provided for in Attachment C to the OATT. This includes receiving initial AFC values from the RC, calculating final AFC values using the algorithms included in Attachment C, and converting the AFC to ATC using OATI software.

- Post on OASIS the mathematical algorithms used to calculate firm and non-firm AFC. TranServ shall also post the results of the AFC calculations on OASIS.
- Daily review of transmission service requests (TSRs) and eTag action and statistics.
- Daily review of posted AFC/ATC information and investigation into any anomalies.
- Review, observation, and validation of the Total Transfer Capability (TTC) development process.

3.1.4 Interchange and Scheduling

- As the Transmission Service Provider, responsible for the following activities:
  - Confirm that each electronic schedule (e-Tag) has a confirmed transmission service request.
  - Approve the interchange schedules as the transmission service provider.
  - Curtail electronic schedules if requested by the RC or Balancing Authority (BA).
  - Monitor and validate the Net Scheduled Interchange (NSI), as processed by OATI software, to ensure timely creation of the NSI data file with a syntactical quality check on the data set.

3.1.5 Transmission Planning

- TranServ will participate in Company's transmission planning process as outlined in Attachment K to the OATT, including the following activities:
  - Review and approve Company's long-term (generally one year and beyond) plan for the reliability/adequacy of Company's Transmission System.
  - Review and approve Transmission System models (steady state, dynamics, and short circuit).
  - Develop alternatives to Planning Redispatch service.
  - Notify impacted transmission entities of any planned transmission changes that may influence their facilities.

- Participate with the SPC and associated SPC working groups, as required.
- Participate in the overall OATT Attachment K process as observer.
- The Parties agree that the final annual transmission plan and decision of whether/when to construct and expand the system rests with Company.
- Both parties will communicate openly and in a timely manner; each will perform their respective work; and both will continually work together to improve mutual and individual processes in a joint effort to assure work is completed pursuant to Company standards and deadlines.

3.1.6 Compliance

- Establish and adhere to a "culture of compliance" for TranServ Personnel and TranServ Designees consistent with FERC's Policy Statement on Compliance, 125 FERC ¶ 61,058 (2008) as may be supplemented or amended by further FERC orders. TranServ shall take such reasonable steps requested by the Company in furtherance of such a culture of compliance.
- In accordance with *Louisville Gas and Electric Company*, 114 FERC ¶ 61,282 at P 152 (2006), provide FERC with semi-annual reports "detailing concerns expressed by stakeholders and [ITO's] response to those concerns as well as any issues or tariff provisions that hinder [ITO] from performing its required duties" as requested.
- Maintain records and provide reports as required by the Kentucky Public Service Commission (KPSC), OATT, Department of Energy (DOE), FERC, NERC, SERC Reliability Corporation (SERC) or NAESB. Without limiting the foregoing, Company may from time-to-time provide TranServ with specific direction as to records that Company expects to support compliance efforts, and TranServ shall maintain such records as directed.
- Assist Company, as requested by Company, in the preparation of applications, audit materials, filings, reports or responses to any Regulatory Authority. Without limiting the foregoing, this assistance may include from time-to-time preparation for (and participation in, if appropriate) FERC or NERC audits and providing event analysis information for FERC, NERC or SERC. TranServ's support shall be provided in a time frame reasonably requested by Company.
- Monitor FERC, NERC, SERC, and NAESB activities for changes in standards or compliance requirements that may require modification to the ITO Services or other

coordination with Company. To the extent possible, TranServ shall notify Company of any proposed or pending modifications prior to their implementation. The Parties shall work together to establish a work plan and timetable for implementation of any such changes. The Parties agree that all changes to ITO Services resulting from legal and regulatory developments as well Company requests, shall be assessed using the change order process detailed in Section 5 of this Appendix A.

3.2 Transmission Planner

TranServ will provide certain services to LG&E/KU, the Transmission Planner (TP). The services include:

3.2.1 Customer Interface

- TranServ will participate in the drafting of Business Practices; including any FERC or NAESB required Business Practices. Company shall have final review, ownership, and approval for all Business Practices.
- TranServ will participate in periodic reviews of, and provide expertise/comments on the OATT. Company retains final authority over the OATT's content, including retaining the right and responsibility to file changes to the OATT.
- Responsible for planning, coordinating and holding regular stakeholder meetings and/or conference calls. These stakeholder meetings will include TranServ, Company, and the RC, and other entities as required, to address concerns regarding Company's system, administration of the OATT, and related issues. This activity includes (as necessary) performing background checks for stakeholders who desire access to Critical Energy Infrastructure Information (CEII), preparing meeting materials, facilitating the meeting, and preparing post-meeting minutes for posting on OASIS.
- Responsible for coordinating with third-party transmission system owners and operators as necessary to support customer service requests. This includes coordinating the provision of any data from Company to the third-party system.

3.3 LG&E/KU

TranServ understands that Company has the following responsibilities in support of the ITO Services under this Appendix A:

3.3.1 Customer Interface

- Contracting for the OATI webSmartOASIS service that meets FERC and NAESB requirements.
- Contracting for the OATI webTrans service used to evaluate and take actions on transmission service requests and e-Tags.
- Continuation of Agreement with the RC to provide necessary data for AFC/ATC calculation and posting processes.
- Final review, ownership, and approval for all Business Practices.
- Final authority over the OATT's content, including the right and responsibility to file changes to the OATT.
- Cooperate in the coordination with third-party systems as necessary to support customer service requests. This includes coordinating the provision of any data from Company to the third-party system.

3.3.2 Compliance

- From time-to-time provide TranServ with specific direction as to records that Company expects to support compliance efforts, TranServ shall maintain such records as directed in order to provide reports as required by the KPSC, OATT, DOE, FERC, NERC, SERC or NAESB.
- Respond to TranServ notifications of FERC, NERC, SERC, and NAESB activities for changes in standards or compliance requirements that may require modification to the ITO Services or other coordination with Company within requested response timelines. Work together with ITO to establish a work plan and timetable for implementation of any such changes. The Parties agree that all changes to ITO Services resulting from legal and regulatory developments as well Company requests, shall be assessed using the change order process detailed in Section 5 of this Appendix A.

4. Customer Support

TranServ will provide support for Service 24-hours per day and 365-days per year by utilizing a single point of contact support staff. During Normal Business Hours the support staff can be contacted by telephone or by e-mail as outlined in published TranServ's ITO Support Information. After Normal Business Hours support is achieved through telephone only. TranServ will take all reasonable effort to ensure that reported problems or other Customer support related events are responded to within 30-minutes of the event notification when ITO Support Procedures are followed.

4.1 Problem Resolution

Problems or outages are reported to TranServ by following customer support processes. All problems or questions are assigned a severity level by mutual agreement of the parties. Problems which are considered Critical or High in severity should be reported to TranServ at any time. Problems considered Medium or Low severity should be reported by phone during business hours or by e-mail at any time. The severity level classifications are defined as follows:

Critical - Problems or issues that are impacting business immediately or impacting grid reliability and action is required prior to next business day.

High - Problems or issues that affect a key functionality of Service component and there is no work around available but immediate business or grid reliability impact is not present.

Medium - Business processes are impacted, but satisfactory work around is in place to avoid business interruptions.

Low - Customer inquiries or reported problems and issues that create nuisances or inconveniences for the customer. Minimal or no business impact is occurring.

Ticket Resolution		
Action	**TranServ Responsibility**	**Time To Remedy**
Correct a 'Critical' severity Problem or Issue	During normal business hours TranServ will respond to reported Critical severity problems and begin corrective action immediately until either a satisfactory work around is in place or problem is resolved. Outside of normal business hours TranServ will respond to reported Critical severity problems within 30-minutes of notification. Escalation to responsible TranServ senior management will occur in all cases.	TranServ will work continuously until resolution is in place. This may include a temporary work around until a permanent correction can be implemented. **Performance goal is to resolve all Critical severity tickets within 4-hours.**
Correct a 'High' severity Problem or Issue	During normal business hours TranServ will respond to reported High severity problems and begin corrective action to resolve with either a satisfactory work around or problem resolution prior to end of business day. Outside of normal business hours TranServ will respond to reported High severity problems within 30-minutes of notification. Escalation to responsible TranServ senior management will occur in all cases.	TranServ will provide an initial problem analysis update within 8-hours at all times. This may include a recommended temporary work around until a permanent correction can be implemented. **Performance goal is to resolve all High severity tickets within 24-hours.**
Correct a 'Medium' severity Problem or Issue	TranServ will schedule corrective action jointly with Customer. Problems of Medium severity should be reported by telephone during business hours or by e-mail at any time.	TranServ will provide an initial problem analysis update within 3-business days of notification of problem. An appropriate action plan and resolution schedule will be mutually agreed to with the Customer. **Performance goal is to resolve all Medium severity tickets by agreed to commitment date.**
Correct a 'Low' severity Problem or Issue	TranServ will schedule corrective action jointly with Customer. Problems of Low severity should be reported by telephone during business hours or by e-mail at any time.	TranServ will provide an initial problem analysis update within 5-business days. An appropriate action plan and resolution schedule will be mutually agreed to with the Customer. **Performance goal is to resolve all Low severity**

		tickets by agreed to commitment date.

4.1.1 Tickets - OATI webSupport

To ensure all customers of TranServ receive a high level of customer service all calls or e-mails with questions or reported problems are documented in a Ticket. All TranServ staff members utilize OATI webSupport, an issue reporting and assignment platform allowing tracking and confirmed resolution of all issues reported to TranServ. Upon receiving a communication from a customer, TranServ will open a webSupport Ticket. The Ticket contains customer contact information, data metrics on the type of problem, an identification of the TranServ staff member to whom the Ticket is currently assigned, a detailed description of the problem, and a detailed description of the problem's current status which will eventually include a description of how the issue was resolved. The TranServ staff member provides the Ticket number to the customer for all issues not resolved immediately. If the issue cannot be resolved by the TranServ staff member creating the Ticket, the Ticket is reassigned to another member of the TranServ team. The TranServ staff member who initially created the Ticket is expected to use webSupport's monitoring capability to determine unresolved Tickets, and to reassign or escalate it as necessary at any time to promote prompt resolution within response timing guidelines.

4.1.2 Response Time

TranServ support staff will answer all calls as received during normal business hours and take all reasonable effort to resolve issues at the time of call. For issues and problems that are not immediately resolved, TranServ will follow normal processing for assigned severity level and notify customer once resolution occurs.

Calls to support staff outside of normal business hours will be answered as received and customer will be notified within 30-minutes on planned actions to be taken by TranServ support staff in accordance with normal processing for assigned severity level.

4.1.2.1 Ticket Escalation

Problem tickets that cannot be resolved in accordance with normal processing for assigned severity level will be escalated to appropriate TranServ management. Customers may request immediate ticket escalation to appropriate TranServ management.

4.1.2.2 Customer Satisfaction

Customer satisfaction inquiries are automatically sent to customers upon the closing of a ticket. The results of these surveys result in improved performance by customer support staff or changes in business processes.

5. Service Modifications

From time to time Company may require a modification to an existing Service function. Such modifications may be prompted by changes in regulatory compliance requirements, or by a Company request. Minor modifications that require reasonably minimal resource commitment from TranServ staff will be included within a reasonable time period at no cost to Company. Modifications that may have more significant impact on Service design or will impact TranServ staff resource commitments more than minimally will be discussed with Company and may in some instances require additional payment by Company, or likewise, require a decrease in payment by Company. Each of these change requests will be described in a written Change Order. Each Change Order will be scheduled for implementation upon written agreement with Company as to scope, cost and schedule.

5.1 Minor Changes

Any change to an existing Service function that does not have a significant impact on Service design or require TranServ to staff or contract with additional personnel, if even for a brief period of time, to prepare for and/or meet the requirements of the change (a “Minor Change”) will be integrated into Company’s Service at no cost to Company. A written Change Order will be negotiated and executed between Company and TranServ prior to implementation of any Minor Change.

5.2 Major Changes

Any change to an existing Service function that has a significant impact on Service design or requires TranServ to staff additional or fewer personnel, if even for a brief period of time, in order to prepare for and/or meet the requirements of the change (a “Major Change”) will require a written Change Order which must be negotiated and executed between Company and TranServ prior to implementation of any Major Change.

6. Reliability Coordination

TranServ will be required to coordinate its operations with the LG&E/KU designated RC. The RC is responsible for performing certain reliability related tasks for the LG&E/KU system, including acting as the NERC-registered Reliability Coordinator. The RC’s responsibilities are detailed in the Reliability Coordinator Agreement and Attachment P to the LG&E/KU OATT.

AMENDED AND RESTATED RELIABILITY COORDINATOR AGREEMENT

BETWEEN

LOUISVILLE GAS AND ELECTRIC COMPANY
AND KENTUCKY UTILITIES COMPANY

AND

TENNESSEE VALLEY AUTHORITY

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Exhibit 1 - Congestion Management Process

RELIABILITY COORDINATOR AGREEMENT

This Amended and Restated Reliability Coordinator Agreement (this "Agreement"), including all appendices, exhibits, and attachments, appended hereto, is entered into this 25th day of August, 2014 ("Execution Date"), between Louisville Gas and Electric Company and Kentucky Utilities Company, corporations organized pursuant to the laws of the State of Kentucky (collectively, "LG&E/KU"), and the Tennessee Valley Authority, a federal government corporation ("TVA" and, in its capacity as reliability coordinator pursuant to this Agreement, the "Reliability Coordinator") created by and existing under and by virtue of the Tennessee Valley Authority Act of 1933, as amended, 16 U.S.C. §§ 831 *et seq.* (the "TVA Act"). LG&E/KU and the Reliability Coordinator may sometimes be referred to herein individually as a "Party" and collectively as the "Parties."

RECITALS

WHEREAS, LG&E/KU owns, among other things, an integrated electric transmission system ("Transmission System"), over which they currently provide open access transmission service to customers in the LG&E/KU Balancing Authority Area (as defined in Section 1.5 of LG&E/KU's Open Access Transmission Tariff, as on file with the Federal Energy Regulatory Commission ("FERC") and as may be changed from time to time (the "OATT"));

WHEREAS, LG&E/KU desires to have the Reliability Coordinator perform certain key reliability functions under the OATT, including: (i) reliability coordination (as defined in the relevant North American Electric Reliability Council ("NERC") Standards); (ii) transmission planning and regional coordination; (iii) approving LG&E/KU's maintenance schedules; (iv) identifying upgrades required to maintain reliability; (v) non-binding recommendations relating to economic transmission system upgrades; and (vi) administration of any seams agreements;

WHEREAS, LG&E/KU desires to have the Reliability Coordinator perform all functions identified for reliability coordinators in NERC's Standards;

WHEREAS, LG&E/KU will retain all remaining NERC obligations, including obligations associated with its status as a Control Area (including operations as a Balancing Authority and Transmission Operator as defined by NERC) and its obligations to ensure the provision of transmission services under the OATT, and will take action necessary to protect reliability of the Transmission System, including circumstances where such action is necessary to protect, prevent or manage emergency situations;

WHEREAS, the Reliability Coordinator is: (i) a federal government corporation charged with providing electric power, flood control, navigational control, agricultural and industrial development, and other services to a region including Tennessee and parts of six contiguous states; and (ii) recognized by NERC as a reliability coordinator;

WHEREAS, the Reliability Coordinator is independent from LG&E/KU, possesses the necessary competence and experience to perform the functions provided for hereunder and is willing to perform such functions under the terms and conditions agreed upon by the Parties as set forth in this Agreement;

WHEREAS, as part of LG&E/KU's goal to maintain the requisite level of independence in the operation of its Transmission System to prevent any exercise of transmission market power, LG&E/KU has entered into an Independent Transmission Organization Agreement (the "Independent Transmission Organization Agreement") with TranServ International, Inc. (the "Independent Transmission Organization" or "ITO"), pursuant to which the Independent Transmission Organization provides to LG&E/KU certain key transmission-related functions under the OATT;

WHEREAS, LG&E/KU seeks to ensure the full participation of the LG&E/KU Transmission System in the arrangements and protocols included in Congestion Management Process ("CMP"), which is Exhibit 1 hereto;

WHEREAS, through the Joint Reliability Coordination Agreement ("JRCA") between TVA and PJM Interconnection, L.L.C. ("PJM"), TVA and PJM participate in CMP;

WHEREAS, the Midcontinent Independent Operator, Inc. ("MISO"), through its Joint Operating Agreement with PJM, also participates in the CMP;

WHEREAS, by virtue of the reciprocity requirements found in Section 6.2 of the CMP, TVA will coordinate with MISO in order to manage regional coordination issues applicable under the CMP between the LG&E/KU system and MISO;

WHEREAS, TVA and LG&E/KU may choose to participate in similar reliability coordination agreements with other neighboring reliability coordination areas.

NOW THEREFORE, in consideration of the mutual promises contained herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties hereby agree as follows:

Section 1 - Designation; Scope of Functions; Standards of Performance; Reliability Coordination Advisory Committee.

1.1 Designation. LG&E/KU appoints TVA to act as LG&E/KU's designated Reliability Coordinator pursuant to and in accordance with the terms and conditions of this Agreement. The Reliability Coordinator shall have no responsibility to LG&E/KU, except as specifically set forth in this Agreement.

1.2 Scope of Functions. The Reliability Coordinator shall perform the functions assigned to it and described in Attachment A and Attachment B (the "Functions") seven days a week, twenty-four hours a day, for the duration of the Term in accordance with the terms and conditions of this Agreement. In accordance with its obligations under this Section 1.2, the Reliability Coordinator is authorized to, and shall, direct and coordinate timely and appropriate actions by LG&E/KU, including curtailing transmission service or energy schedules, redispatching generation, and shedding load, in each case, in order to avoid adverse effects on interregional bulk power reliability.

1.2.1 Relationship Between this Agreement and Attachment L to LG&E/KU's OATT. The Parties recognize that the relationship between LG&E/KU

and the Reliability Coordinator and the Functions to be performed by the Reliability Coordinator must be reflected in LG&E/KU's OATT. The Reliability Coordinator relationship and the Functions assigned to the Reliability Coordinator under Attachment A and Attachment B to this Agreement shall be reflected in Attachment L to LG&E/KU's OATT. To the extent that there is a conflict between Attachment A and/or Attachment B to this Agreement and Attachment L to LG&E/KU's OATT, Attachment L to LG&E/KU's OATT shall govern. Any changes proposed by LG&E/KU to FERC in Attachment L in LG&E/KU's OATT, pursuant to Section 5.3 of Attachment L in LG&E/KU's OATT, regarding the Functions or any other provisions that concern the Reliability Coordinator shall reflect the mutual agreement of the Parties. Notwithstanding this Section 1.2.1, nothing in this Agreement or Attachment L to LG&E/KU's OATT shall grant FERC any additional jurisdiction over TVA.

1.3 <u>Reliability Coordinator Procedures</u>. The Reliability Coordinator shall develop the procedures and guidelines by which it will perform the Functions (the "<u>Reliability Coordinator Procedures</u>") in coordination with the RCAC (as defined in <u>Section 1.10</u>) and applicable regional reliability councils. The Reliability Coordinator Procedures shall be documented in a NERC-approved reliability plan for the TVA Reliability Coordination Area or in TVA Standard Procedures and Policies. The Reliability Coordinator shall provide LG&E/KU advance written notice of any amendment or change to the Reliability Coordinator Procedures. For purposes of this Agreement, the term "TVA Standard Procedures and Policies" shall mean such procedures and policies related to TVA's operations as may be promulgated and published by TVA pursuant to its legal authorities and obligations.

1.4 <u>Threat to Reliability</u>. If the Reliability Coordinator determines that an actual or potential threat to transmission system reliability exists, and that such threat may impair the reliability of a transmission system, then the Reliability Coordinator shall direct that LG&E/KU take whatever actions are necessary, consistent with Good Utility Practice (as defined below) and in accordance with the applicable reliability criteria, policies, standards, rules, regulations and other requirements of NERC (collectively, the "<u>NERC Standards</u>") and any applicable regional reliability councils or their successors (collectively, "<u>Regional Reliability Council Standards</u>"), to avoid or mitigate the effects of the threat to transmission system reliability. For purposes of this Agreement, "<u>Good Utility Practice</u>" shall mean any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts that, in a person's exercise of reasonable judgment in light of the facts as known to that person at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to include the range of acceptable practices, methods, or acts generally accepted in the region.

1.5 <u>Reliability Coordinator Directives</u>. Except as provided in the immediately succeeding sentence, LG&E/KU shall implement any directive given by the Reliability Coordinator pursuant to <u>Sections 1.2</u> or <u>1.4</u>. LG&E/KU shall not be obligated to implement any directive which LG&E/KU determines will violate any state or federal law or the terms of any governmental approval applicable to LG&E/KU. LG&E/KU may review any directive given by the Reliability Coordinator pursuant to Sections 1.2 or 1.4, to determine if it is, in LG&E/KU's judgment, in accordance with the requirements of Section 1.8. If LG&E/KU determines that any directive is not in accordance with the requirements of Section 1.8, then it shall immediately so notify the Reliability Coordinator; provided, however, that, except as provided in the second sentence in this Section 1.5, LG&E/KU shall continue to implement the directive until the Reliability Coordinator notifies LG&E/KU otherwise. LG&E/KU's notice to the Reliability Coordinator shall include: (a) information outlining the basis for LG&E/KU's determination that (i) the directive is not in accordance with the requirements of Section 1.8 and, if applicable, (ii) that implementation of the directive will violate one or more state or federal laws or the terms of any governmental approvals applicable to LG&E/KU; and (b) the alternative action that LG&E/KU would prefer to take to alleviate the problem addressed by the Reliability Coordinator's directive. After prompt consideration of such information, the Reliability Coordinator shall issue a directive to LG&E/KU in accordance with its obligations under this Agreement and LG&E/KU will, subject to the second sentence in this Section 1.5, act in accordance with such directive.

1.6 Coordination with Independent Transmission Organization. In conjunction with its performance of the Functions, the Reliability Coordinator shall coordinate and cooperate with the Independent Transmission Organization and provide, subject to the terms and conditions of this Agreement, including the Reliability Coordinator's obligations with respect to Confidential Information in Section 10, any information that the Independent Transmission Organization may reasonably request in order to carry out its functions under the Independent Transmission Organization Agreement.

1.7 Expansion. Nothing in this Agreement is intended to prevent TVA from (a) coordinating, or cooperating in, interregional activities to relieve problems experienced by other transmission systems or (b) entering into other agreements with one or more third party transmission providers or operators to perform functions for such transmission providers or operators that are the same or similar to the Functions performed hereunder; provided, however, that it does not breach any of its obligations under this Agreement (including its obligations with respect to Confidential Information in Section 10) by entering into or performing any of its obligations under such other agreements; provided, further, that (i) any such other agreements shall provide for LG&E/KU to be reimbursed in an equitable manner for any capital expenditures made pursuant to this Agreement as well as for LG&E/KU's ongoing operations and maintenance expenditures to the extent such capital expenditures and operations and maintenance expenditures are used by the Reliability Coordinator in performing functions under such other agreements, (ii) LG&E/KU agrees to reimburse any such third party transmission providers or operators in an equitable manner for any capital expenditures made by such third parties as well as for such third parties' ongoing operations and maintenance expenditures to the extent such capital expenditures and operations and maintenance expenditures are used by the Reliability Coordinator in performing functions under this Agreement, and (iii) to the extent applicable, the Reliability Coordinator shall revise the compensation provided for in Section 3.1 in accordance with the terms therein.

1.8 Reliability Coordinator's Standard of Performance. The Reliability Coordinator shall perform its obligations under this Agreement in accordance with: (a) Good Utility Practice; (b) the NERC Standards and Regional Reliability Council Standards; (c) LG&E/KU's specific reliability requirements and operating guidelines (to the extent these are not inconsistent with other requirements specified in this Section 1.8); (d) TVA Standard Procedures and Policies; and, (e) all state and federal laws, including the TVA Act, and the terms of governmental approvals applicable to one or both of the Parties. In performing its responsibilities under this Agreement, the Reliability Coordinator shall not discriminate against similarly situated persons.

1.9 LG&E/KU's Standard of Performance. LG&E/KU shall perform its obligations under this Agreement in accordance with: (a) Good Utility Practice; (b) the NERC Standards and Regional Reliability Council Standards; (c) any other LG&E/KU-specific reliability requirements and operating guidelines (to the extent these are not inconsistent with other requirements specified in this Section 1.9); and (d) all state and federal laws and the terms of governmental approvals applicable to LG&E/KU.

1.10 Reliability Coordination Advisory Committee.

1.10.1 Each Party shall designate one representative to serve on a Reliability Coordination Advisory Committee ("RCAC"), which shall be composed of representatives of each Party and representatives from each entity that has executed a similar reliability coordination agreement designating TVA as its reliability coordinator. Each Party may also designate one alternate to act in the absence of its representative on the RCAC. Written notice of each representative and alternate appointment shall be provided to each RCAC entity, and each Party may change its representatives upon written notice to the other RCAC entities.

1.10.2 The RCAC shall assist the Reliability Coordinator in the development of the initial Reliability Coordinator Procedures and the modification of existing Reliability Coordinator Procedures. In connection with these activities, the Reliability Coordinator may provide the other RCAC members with access to necessary data and documents maintained by the Reliability Coordinator, provided that each such RCAC member has signed the NERC Data Confidentiality Agreement and that all Confidential Information is treated as transmission operations and transmission system information pursuant to the NERC Data Confidentiality Agreement.

The RCAC shall meet at least once per Contract Year (as defined below). For purposes of this Agreement, a "Contract Year" shall consist of a twelve (12) month period. "Contract Year 1" shall begin on the Effective Date. Contract Years 2, 3, and 4 shall consist of the next three successive 12-month periods after Contract Year 1.

Section 2 - Independence.

2.1 Key Personnel. All Functions shall be performed by employees of the Reliability Coordinator identified in Attachment C (the "Key Personnel"). The Reliability

Coordinator may from time to time change the names of the employees identified as Key Personnel by notice to LG&E/KU in accordance with Section 15.1. No Key Personnel shall also be employed by LG&E/KU or any of its Affiliates (as defined in 18 C.F.R. § 35.34(b)(3) of FERC's regulations). The Reliability Coordinator and the Key Personnel shall be, and shall remain throughout the Term, Independent (as defined below) of LG&E/KU, its Affiliates and the Independent Transmission Organization. For purposes of this Agreement: "Independent" shall mean that the Reliability Coordinator and the Key Personnel are not subject to the control of LG&E/KU, its Affiliates or the Independent Transmission Organization, and have full decision making authority to perform all Functions in accordance with the provisions of this Agreement. Any Key Personnel owning securities in LG&E/KU, its Affiliates or the Independent Transmission Organization shall divest such securities within six (6) months of first being assigned to perform such Functions, provided that nothing in this Section 2.1 shall be interpreted or construed to preclude any such Key Personnel from indirectly owning securities issued by LG&E/KU, its Affiliates or the Independent Transmission Organization through a mutual fund or similar arrangement (other than a fund or arrangement specifically targeted toward the electric industry or the electric utility industry or any segment thereof) under which the Key Personnel does not control the purchase or sale of such securities. Participation by any Key Personnel in a pension plan of LG&E/KU, its Affiliates or the Independent Transmission Organization shall not be deemed to be a direct financial interest if the plan is a defined-benefit plan that does not involve the Key Personnel's ownership of the securities. For the avoidance of doubt, LG&E/KU shall not have an approval or consent right with respect to the selection of any Key Personnel.

2.2 Standards of Conduct Treatment. All Key Personnel shall be treated, for purposes of FERC's Standards of Conduct, as transmission employees. All restrictions relating to information sharing and other relationships between merchant employees and transmission employees shall apply to the Key Personnel.

Section 3 - Compensation, Billing and Payment.

3.1 Compensation. LG&E/KU shall pay to the Reliability Coordinator as compensation for the performance of the Functions under this Agreement as follows:

Subsequent Term Beginning	Amount
September 1, 2014	$2,375,000
September 1, 2015	$2,422,500
September 1, 2016	$2,470,950
September 1, 2017	$2,520,369
September 1, 2018	$2,570,776

The Reliability Coordinator agrees that if at any time during the Term it expands its Reliability Coordination Area by providing similar services to additional Transmission Operators, the Reliability Coordinator will review and revise, as appropriate, the above compensation rate. Such revised compensation shall enable the Reliability Coordinator to recover its incremental costs associated with providing the specific service by allocating the costs among those subscribing to the service in an equitable manner (*e.g.*, costs may be allocated using a load ratio share methodology (a participant's annual non-coincident peak load as a percentage of the total annual non-coincident peak load for those participating in the service)). Costs will be determined by the Reliability Coordinator based on its total cost of providing the service(s) as documented in the Reliability Coordinator's financial systems.

Compensation for Subsequent Terms (as defined in Section 4.2 herein) beyond those delineated above shall be based on the compensation in previous Contract Years and/or the methodology outlined above in this Section 3.1 and shall be negotiated by the Parties in good faith. Such negotiations shall begin not later than six months prior to, and shall be concluded no later than three months prior to, the beginning of the Subsequent Term.

Notwithstanding any provision to the contrary contained in this Agreement, if a Dispute should occur between the Parties with respect to the amount of compensation to be paid by LG&E/KU to the Reliability Coordinator (i) pursuant to this Sections 3.1 or (ii) in respect of additional services (other than the Functions) requested by LG&E/KU that the Reliability Coordinator elects, in its sole discretion, to provide, then, in each case, LG&E/KU shall file notice thereof with FERC. The Parties acknowledge that any FERC order issued with respect to such a dispute is only binding on LG&E/KU, not TVA.

3.2 Compensation After Termination. If LG&E/KU terminates this Agreement before the end of a Contract Year, then the Reliability Coordinator shall not be obligated to refund any amounts paid by LG&E/KU to the Reliability Coordinator as compensation for services provided by the Reliability Coordinator under this Agreement. If, however, the Reliability Coordinator terminates this Agreement before the end of a Contract Year or LG&E/KU and the Reliability Coordinator mutually agree to terminate this Agreement, then the Reliability Coordinator shall be obligated to refund to LG&E/KU an amount equal to the product of (a) any amounts paid by LG&E/KU to the Reliability Coordinator as compensation for services provided by the Reliability Coordinator under this Agreement during the Contract Year in which this Agreement is terminated and (b) the number of whole or partial months remaining in the Contract Year divided by twelve (12).

3.3 Reimbursement of Additional Costs. In addition to the compensation provided for in Section 3.1, LG&E/KU shall reimburse the Reliability Coordinator for (a) any additional costs incurred by the Reliability Coordinator at the request or direction of LG&E/KU or (b) any reasonable additional one-time costs necessarily incurred by Reliability Coordinator related to its activities under this Agreement that are not associated with services provided for in Section 3.1. Any costs under item (b) above shall be appropriately allocated by TVA among the Parties and those other entities that have executed similar reliability coordination agreements designating TVA as their reliability coordinator.

3.4 Payments. All payments by LG&E/KU to the Reliability Coordinator shall be made by the FedWire transfer method to the Reliability Coordinator’s account at the U.S. Treasury in accordance with the wire instructions indicated below, and all such payments shall be deemed received as of the date the electronic funds transfer to the Reliability Coordinator’s account is deemed effective.

Bank Name: TREAS NYC (official abbreviation)

Bank Address: New York Federal Reserve Bank, New York City
33 Liberty Street
New York, New York 10045

ABA Number: 021030004

Account No: 0004912

Beneficiary: Tennessee Valley Authority

Taxpayer ID: 62-0474417

OBI: Provide your organization name and invoice number or explanation of payment.

The Reliability Coordinator shall provide LG&E/KU with one or more contact persons for payment purposes and shall update such list of contact persons as necessary.

Section 4 - Effective Date; Term; Termination; Termination Fees; Transition Assistance Services.

4.1 Effective Date. The Parties acknowledge and agree that the effective date of this Agreement (the "Effective Date") shall be September 1, 2014 or such other date as permitted by FERC

4.2 Term. This Agreement shall commence on Effective Date (as provided for in Section 4.1), and shall automatically continue for successive one-year terms (each, a "Subsequent Term") unless and until terminated pursuant to the termination provisions hereof. All Subsequent Terms, together with the Transition Assistance Period, if any, shall collectively be referred to as the "Term."

4.3 Mutually-Agreed Termination. This Agreement may be terminated by mutual agreement of the Parties at any time during the Term.

4.4 Termination at End of Term. Either Party may terminate this Agreement at the end of any Subsequent Term upon one (1) year's prior written notice to the other Party.

4.5 Termination for Cause.

4.5.1 Termination by Either Party. Either Party may terminate this Agreement effective immediately upon thirty (30) days' prior written notice thereof to the other Party if:

(a) Material Failure or Default. The other Party fails to comply with, observe or perform, or defaults, in any material respect, in the performance of the terms and conditions of this Agreement, and such failure or default remains uncured for thirty (30) days after notice thereof, provided that such failure or default is susceptible to cure and the other Party is exercising reasonable diligence to cure such failure or default;

(b) Pattern of Failure. It determines, in its sole discretion, that there has been a pattern of failure by the other Party to comply with the standards of performance required under this Agreement;

(c) Gross Negligence, Willful Misconduct or Fraud. The other Party commits gross negligence, willful misconduct or fraud in the performance of its obligations under this Agreement;

(d) Material Misrepresentation. Any representation made by the other Party hereunder shall be false or incorrect in any material respect when made and such misrepresentation is not cured within thirty (30) days of such discovery or is incapable of cure;

(e) Bankruptcy. The other Party: (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it; (ii) makes an assignment or any general arrangement for the benefit of creditors; (iii) otherwise becomes bankrupt or insolvent (however evidenced); (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets; or (v) is generally unable to pay its debts as they fall due;

(f) Dissolution. The other Party dissolves or is dissolved or its legal existence is otherwise terminated;

(g) Failure to Negotiate Amendment. The Parties are unsuccessful in negotiating an amendment or amendments to this Agreement pursuant to Section 17.6;

(h) Regulatory Changes/Modifications. FERC, in accepting this Agreement for filing, makes any material changes, modifications, additions, or deletions to this Agreement; or

(i) Extended Force Majeure. A Party is excused because of Force Majeure (as defined in Section 11 herein) for more than thirty (30) days from performing any of its material obligations under this Agreement.

4.5.2 Termination by LG&E/KU. LG&E/KU may terminate this Agreement effective immediately upon thirty (30) days' prior written notice thereof to the Reliability Coordinator if:

(a) the Reliability Coordinator loses its NERC certification once obtained; or

(b) FERC issues an order determining that TVA should no longer serve as LG&E/KU's Reliability Coordinator pursuant to this Agreement.

4.5.3 Termination by the Reliability Coordinator. The Reliability Coordinator may terminate this Agreement effective immediately upon thirty (30) days' prior written notice thereof to LG&E/KU if:

(a) LG&E/KU determines to cease being a Balancing Authority and/or Transmission Operator, provided that LG&E/KU shall provide the Reliability Coordinator as much advance written notice of such determination as is practicable to allow the Reliability Coordinator to terminate this Agreement on or prior to the time LG&E/KU ceases to be a Balancing Authority or Transmission Operator;

(b) FERC or any other person or entity takes any action to subject the Reliability Coordinator to FERC's plenary jurisdiction under the Federal Power Act ("FPA"); or

(c) Effective Date has not occurred within eighteen (18) months of the Execution Date.

4.6 Return of Materials. Upon any termination of this Agreement or the conclusion of any Transition Assistance Period pursuant to Section 4.8.1, whichever is later, the Reliability Coordinator shall timely and orderly turn over to LG&E/KU all materials that were prepared or developed prior thereto pursuant to this Agreement, and return or destroy, at the option of LG&E/KU, all Data and other information supplied by LG&E/KU to the Reliability Coordinator or created by the Reliability Coordinator on behalf of LG&E/KU.

4.7 Survival. All provisions of this Agreement which are by their nature or terms intended to survive the termination of this Agreement, including the obligations set forth in Sections 7 and 10, shall survive termination of this Agreement.

4.8 Transition Assistance Services.

4.8.1 Transition Assistance Period. Commencing on the date this Agreement is terminated and continuing for up to one (1) year thereafter (the "Transition Assistance Period"), the Reliability Coordinator shall (a) provide the Functions (and any replacements thereof or substitutions therefor), to the extent LG&E/KU requests such Functions to be performed during the Transition Assistance Period, and (b) cooperate with LG&E/KU in the transfer of the Functions (collectively, the "Transition Assistance Services"). During the Transition Assistance Period, the Parties shall use good faith efforts to ensure a smooth transition.

4.8.2 Transition Assistance Services. The Reliability Coordinator shall, upon LG&E/KU's request, provide the Transition Assistance Services during the Transition Assistance Period at the Reliability Coordinator's actual cost for such services. The quality and level of performance of the Functions by the Reliability Coordinator during the Transition Assistance Period shall not be degraded. After the expiration of the Transition Assistance Period, the Reliability Coordinator shall answer questions from LG&E/KU regarding the Functions on an "as needed" basis at the Reliability Coordinator's then-standard billing rates.

4.8.3 Key Personnel. During the Transition Assistance Period, the Reliability Coordinator shall not terminate, reassign or otherwise remove any Key Personnel without providing LG&E/KU thirty (30) days' prior notice of such termination, reassignment or removal unless such employee (a) voluntarily resigns from the Reliability Coordinator, (b) is dismissed by the Reliability Coordinator for cause, or (c) dies or is unable to work due to his or her disability.

4.9 Change in Reliability Entity. This Agreement is based on the existence of NERC and the applicability of the NERC Standards. If NERC ceases to exist in its current form or is replaced with an entity with authority over a Party's transmission system, the Parties shall promptly meet to determine whether to revise this Agreement to reflect the new reliability entity, if any, and the Parties' obligations in light of the new reliability entity or to terminate this Agreement in accordance with Section 4.2.

4.10 Prior Obligations and Liabilities Unaffected by Termination. Termination of this Agreement shall not relieve the Parties of any of their respective cost obligations or other obligations and liabilities related to this Agreement that were incurred prior to the effective date of termination of this Agreement.

Section 5 - Data Management.

5.1 Supply of Data. During the Term, LG&E/KU shall supply to the Reliability Coordinator, and/or grant the Reliability Coordinator access to all Data that the Reliability Coordinator reasonably requires to perform the Functions. The Parties shall agree upon the initial format and manner in which such Data shall be provided. For purposes of this Agreement, "Data" means all information, text, drawings, diagrams, images or sounds which are embodied in any electronic or tangible medium and which (a) are supplied or in respect of which access is granted to the Reliability Coordinator by LG&E/KU under this Agreement, which shall be LG&E/KU's Data, (b) are prepared, stored or transmitted by the Reliability Coordinator solely on behalf of LG&E/KU, which shall be LG&E/KU's Data; or (c) are compiled by the Reliability Coordinator by aggregating Data owned by LG&E/KU and Data owned by third parties, which shall be Reliability Coordinator's Data.

5.2 Property of Each Party. Each Party acknowledges that the other Party's Data and the other Party's software, base data models and operating procedures for software or base data models ("Processes") are the property of such other Party and agrees that it will do nothing inconsistent with such ownership, including preserving all intellectual property and/or proprietary rights in such other Party's Data and Processes as provided in Section 6.

5.3 Data Integrity. Each Party shall reasonably assist the other Party in establishing measures to preserve the integrity and prevent any corruption or loss of Data, and the Parties shall reasonably assist each other in the recovery of any corrupted or lost Data. Each Party shall retain and preserve any of the other Party's Data that are supplied to it during the Term, and shall exercise commercially reasonable efforts to preserve the integrity of the other Party's Data that are supplied to it during the Term, in order to prevent any corruption or loss of the other Party's Data.

5.4 Confidentiality. Each Party's Data shall be treated as Confidential Information in accordance with the provisions of Section 10.

Section 6 - Intellectual Property.

6.1 Pre-Existing Intellectual Property. Each Party shall own (and continue to own) all trade secrets, Processes and designs and other intellectual property that it owned prior to entering this Agreement, including any enhancements thereto ("Pre-Existing Intellectual Property"). Each Party acknowledges the ownership of the other Party's Pre-Existing Intellectual Property and agrees that it will do nothing inconsistent with such ownership. Each Party agrees that nothing in this Agreement shall give it any right, title or interest in the other Party's Pre-Existing Intellectual Property, other than the rights set forth in this Agreement. The Reliability Coordinator's Pre-Existing Intellectual Property shall include the Reliability Coordinator Retained Rights set forth in Section 6.3. LG&E/KU's Pre-Existing Intellectual Property shall include LG&E/KU Retained Rights set forth in Section 6.4.

6.1.1 Exclusion. Nothing in this Agreement shall prevent either Party from using general techniques, ideas, concepts and know-how gained by its employees during the performance of its obligations under this Agreement in the furtherance of its normal business, to the extent that it does not result in disclosure of the other Party's Data or any data generated from the other Party's Data or other Confidential Information or an infringement by LG&E/KU or the Reliability Coordinator of any intellectual property right. For the avoidance of doubt, the use by a Party of such general techniques, ideas, concepts and know-how gained by its employees during the performance of its obligations under this Agreement shall not be deemed to be an infringement of the other Party's intellectual property rights so long as such matters are retained in the unaided memories of such employees and any Confidential Information is treated in accordance with the provisions of Section 10.

6.2 Jointly-Owned Intellectual Property. Except for the Data described in Section 5.1, all deliverables, whether software or otherwise, to the extent originated and prepared by the Reliability Coordinator exclusively in connection with the performance of its obligations under this Agreement shall be, upon payment of all amounts that may be due from LG&E/KU to the Reliability Coordinator, jointly owned by LG&E/KU and Reliability Coordinator ("Jointly-Owned Intellectual Property"). Each Party shall have the right to use the Jointly-Owned Intellectual Property without any right or duty or accounting to the other Party, except as provided in this Section 6.2. Upon the Reliability Coordinator using, transferring or licensing Jointly-Owned Intellectual Property for or to a third party, the Reliability Coordinator shall reimburse LG&E/KU in an equitable manner as determined by the Parties in good faith for the actual amounts paid by LG&E/KU to the Reliability Coordinator that relate to such Jointly- Owned Intellectual Property. Except as stated in the foregoing sentence, the Reliability Coordinator shall have no other obligation to account to LG&E/KU for any such use, transfer, license, disclosure, copying, modifying or enhancing of the Jointly-Owned Intellectual Property. Notwithstanding anything herein to the contrary, LG&E/KU may use the Jointly-Owned Intellectual Property for its internal business purposes, including licensing or transferring its interests therein to a third party for purposes of operating or performing functions in connection with LG&E/KU's transmission business.

6.3 Reliability Coordinator Retained Rights. The Reliability Coordinator shall retain all right, title and interest in its proprietary know-how, concepts, techniques, processes, materials and information that were or are developed entirely independently of this Agreement ("Reliability Coordinator Retained Rights"), whether or not such Reliability Coordinator Retained Rights are embodied in a deliverable, whether software or otherwise originated and prepared by the Reliability Coordinator in connection with the performance of its obligations under this Agreement. With respect to the Reliability Coordinator Retained Rights embodied in any deliverable, whether software or otherwise originated and prepared by the Reliability Coordinator in connection with the performance of its obligations under this Agreement, LG&E/KU is hereby granted a nonexclusive, perpetual, worldwide, royalty-free, fully paid-up license under such Reliability Coordinator Retained Rights to use such deliverable for LG&E/KU's internal business purposes only, including licensing or transferring its interests therein to an Affiliate of LG&E/KU or a third party for purposes of operating or performing functions in connection with LG&E/KU's transmission business.

6.4 LG&E/KU Retained Rights. LG&E/KU shall retain all right, title and interest in its proprietary know-how, concepts, techniques, processes, materials and information that were or are developed entirely independently of this Agreement ("LG&E/KU Retained Rights"), whether or not such LG&E/KU Retained Rights are embodied in a deliverable, whether software or otherwise originated and prepared by LG&E/KU in connection with the performance of its obligations under this Agreement. With respect to LG&E/KU Retained Rights embodied in any software or otherwise originated and prepared by LG&E/KU in connection with the performance of its obligations under this Agreement, the Reliability Coordinator is hereby granted a nonexclusive, worldwide, royalty-free, fully paid-up license under such LG&E/KU Retained Rights to use such deliverable for the Reliability Coordinator's performance of its obligations under this Agreement only; provided that LG&E/KU shall not be liable in any way for the use of or reliance on such Reliability Coordinator Retained Rights by the Reliability Coordinator's Affiliate or third party for any purpose whatsoever.

6.5 Reliability Coordinator Non-Infringement; Indemnification. The Reliability Coordinator warrants to LG&E/KU that all Reliability Coordinator's Data and Processes, Reliability Coordinator Pre-Existing Intellectual Property, Reliability Coordinator Retained Rights, and deliverables prepared, produced or first developed by the Reliability Coordinator in connection with the performance of its obligations under this Agreement shall not infringe on any third party patent, copyright, trade secret or other third party proprietary rights. The Reliability Coordinator shall defend, hold harmless and indemnify LG&E/KU and its Affiliates and their respective employees, officers, directors, principals, owners, partners, shareholders, agents, representatives, consultants, and subcontractors (collectively, "LG&E/KU Representatives") from and against all claims, lawsuits, penalties, awards, judgments, court arbitration costs, attorneys' fees, and other reasonable out-of-pocket costs incurred in connection with such claims or lawsuits based upon the actual or alleged infringement of any of the foregoing rights; provided that LG&E/KU gives prompt written notice of any such claim or action to the Reliability Coordinator, permits the Reliability Coordinator to control the defense of any such claim or action with counsel of its choice, and cooperates with the Reliability Coordinator in the defense thereof; and further provided that such claim or action is not based on any alteration, modification or combination of the deliverable with any item, information or process not provided by the Reliability Coordinator, where there would be no infringement in the absence of such alteration, modification or combination. If any infringement action results in a final injunction against LG&E/KU or the LG&E/KU Representatives with respect to Reliability Coordinator's Data and Processes, Reliability Coordinator Pre-Existing Intellectual Property, Reliability Coordinator Retained Rights or deliverables prepared, produced or first developed by the Reliability Coordinator in connection with the performance of its obligations under this Agreement or in the event the use of such matters or any part thereof, is, in such lawsuit, held to constitute infringement, the Reliability Coordinator agrees that it shall, at its option and sole expense, either (a) procure for LG&E/KU or the LG&E/KU Representatives the right to continue using the infringing matter, or (b) replace the infringing matter with non-infringing items of equivalent functionality or modify the same so that it becomes non-infringing and retains its full functionality. If the Reliability Coordinator is unable to accomplish (a) or (b) above, the Reliability Coordinator shall reimburse LG&E/KU for all costs and fees paid by LG&E/KU to the Reliability Coordinator for the infringing matter. The above constitutes the Reliability Coordinator's complete liability for claims of infringement relating to any the Reliability Coordinator's Data and Processes, Reliability Coordinator Pre-Existing Intellectual Property, Reliability Coordinator Retained Rights, and deliverables prepared, produced or first developed by the Reliability Coordinator in connection with the performance of its obligations under this Agreement.

6.6 LG&E/KU Non-Infringement; Indemnification. LG&E/KU warrants to the Reliability Coordinator that, to its knowledge, all LG&E/KU's Data (except for Data created by the Reliability Coordinator on behalf of LG&E/KU) and Processes, LG&E/KU Pre-Existing Intellectual Property, and LG&E/KU Retained Rights shall not infringe on any third party patent, copyright, trade secret or other third party proprietary rights. LG&E/KU shall defend, hold harmless and indemnify the Reliability Coordinator and its Affiliates and their respective employees, officers, directors, principals, owners, partners, shareholders, agents, representatives, consultants, and subcontractors against all claims, lawsuits, penalties, awards, judgments, court costs, and arbitration costs, attorneys' fees, and other reasonable out-of-pocket costs incurred in connection with such claims or lawsuits based upon the actual or alleged infringement of any of the foregoing rights; provided that the Reliability Coordinator gives prompt written notice of any such claim or action to LG&E/KU, permits LG&E/KU to control the defense of any such claim or action with counsel of its choice, and cooperates with LG&E/KU in the defense thereof; and further provided that such claim or action is not based on any alteration, modification or combination of the deliverable with any item, information or process not provided by LG&E/KU to the Reliability Coordinator, where there would be no infringement in the absence of such alteration, modification or combination. The above constitutes LG&E/KU's complete liability for claims of infringement relating to any of the LG&E/KU's Data and Processes, LG&E/KU Pre-Existing Intellectual Property, and LG&E/KU Retained Rights.

Section 7 - Indemnification.

7.1 Indemnification by the Parties. Each Party ("Indemnifying Party") shall indemnify, release, defend, reimburse and hold harmless the other Party and its Affiliates, and their respective directors, officers, employees, principals, representatives and agents (collectively, the "Indemnified Parties") from and against any and all claims, demands, liabilities, losses, causes of action, awards, fines, penalties, litigation, administrative proceedings and investigations, costs and expenses, and attorney fees (each, an "Indemnifiable Loss") asserted against or incurred by any of the Indemnified Parties arising out of, resulting from or based upon (a) a breach by the Indemnifying Party of its obligations under this Agreement, (b) claims of bodily injury or death of any person or damage to real and/or tangible personal property caused by the negligence or willful misconduct of the Indemnifying Party and its Affiliates and their respective directors, officers, employees, principals, representatives, agents or contractors during the Term, or (c) the acts or omissions of the Indemnifying Party and its Affiliates and their respective directors, officers, employees, principals, representatives, agents or contractors during the Term.

7.2 No Consequential Damages. Neither Party shall be liable to the other Party under this Agreement (by way of indemnification, damages or otherwise) for any indirect, incidental, exemplary, punitive, special or consequential damages, except in the case of gross negligence or willful misconduct.

7.3 Cooperation Regarding Claims. If an Indemnified Party receives notice or has knowledge of any Indemnifiable Loss that may result in a claim for indemnification by such Indemnified Party against an Indemnifying Party pursuant to this Section 7, such Indemnified Party shall as promptly as possible give the Indemnifying Party notice of such Indemnifiable Loss, including a reasonably detailed description of the facts and circumstances relating to such Indemnifiable Loss, a complete copy of all notices, pleadings and other papers related thereto, and in reasonable detail the basis for its claim for indemnification with respect thereto. Failure to promptly give such notice or to provide such information and documents shall not relieve the Indemnifying Party from the obligation hereunder to respond to or defend the Indemnified Party against such Indemnifiable Loss unless such failure shall materially diminish the ability of the Indemnifying Party to respond to or to defend the Indemnified Party against such Indemnifiable Loss. The Indemnifying Party, upon its acknowledgment in writing of its obligation to indemnify the Indemnified Party in accordance with this Section 7, shall be entitled to assume the defense or to represent the interest of the Indemnified Party with respect to such Indemnifiable Loss, which shall include the right to select and direct legal counsel and other consultants, appear in proceedings on behalf of such Indemnified Party and to propose, accept or reject offers of settlement, all at its sole cost. If and to the extent that any such settlement is reasonably likely to involve injunctive, equitable or prospective relief or materially and adversely affect the Indemnified Party's business or operations other than as a result of money damages or other money payments, then such settlement will be subject to the reasonable approval of the Indemnified Party. Nothing herein shall prevent an Indemnified Party from retaining its own legal counsel and other consultants and participating in its own defense at its own cost and expense.

Section 8 - Contract Managers; Dispute Resolution.

8.1 LG&E/KU Contract Manager. LG&E/KU shall appoint an individual (the "LG&E/KU Contract Manager") who shall serve as the primary LG&E/KU representative under this Agreement. The LG&E/KU Contract Manager shall (a) have overall responsibility for managing and coordinating the performance of LG&E/KU's obligations under this Agreement, and (b) be authorized to act for and on behalf of LG&E/KU with respect to all matters relating to this Agreement. Notwithstanding the foregoing, the LG&E/KU Contract Manager may, upon prior written notice to the Reliability Coordinator, delegate such of his or her responsibilities to other LG&E/KU employees, as the LG&E/KU Contract Manager deems appropriate. LG&E/KU may, upon prior written notice to the Reliability Coordinator, change the LG&E/KU Contract Manager.

8.2 Reliability Coordinator Contract Manager. The Reliability Coordinator shall appoint, among the Key Personnel identified in Attachment C, an individual (the "Reliability Coordinator Contract Manager") who shall serve as the primary Reliability Coordinator representative under this Agreement. The Reliability Coordinator Contract Manager shall (a) have overall responsibility for managing and coordinating the performance of the Reliability Coordinator's obligations under this Agreement, and (b) be authorized to act for and on behalf of the Reliability Coordinator with respect to all matters relating to this Agreement. Notwithstanding the foregoing, the Reliability Coordinator Contract Manager may, upon prior written notice to LG&E/KU, delegate such of his or her responsibilities to other Key Personnel, as the Reliability Coordinator Contract Manager deems appropriate. The Reliability Coordinator may, upon prior written notice to LG&E/KU, change the Reliability Coordinator Contract Manager. For the avoidance of doubt, LG&E/KU shall not have an approval or consent right with respect to the selection of the Reliability Coordinator Contract Manager.

8.3 Resolution of Disputes. Any dispute, claim or controversy between the Parties arising out of or relating to this Agreement (each, a "Dispute") shall be resolved in accordance with the procedures set forth in this Section 8.3; provided, however, that this Section 8.3 shall not apply to Disputes arising from or relating to (a) the amount of compensation to be paid by LG&E/KU pursuant to the last sentence of Section 3.1, which shall be resolved pursuant thereto, or (b) confidentiality or intellectual property rights (in which case either Party shall be free to seek available legal or equitable remedies).

8.3.1 Notice of Dispute. Each Party shall provide written notice to the other party of any Dispute, including a description of the nature of the Dispute.

8.3.2 Dispute Resolution by Contract Managers. Any Dispute shall first be referred to the LG&E/KU Contract Manager and the Reliability Coordinator Contract Manager, who shall negotiate in good faith to resolve the Dispute.

8.3.3 Dispute Resolution by Executive Management Representatives. If the Dispute is not resolved within fifteen (15) days of being referred to the LG&E/KU Contract Manager and the Reliability Coordinator Contract Manager pursuant to Section 8.3.2, then each Party shall have five (5) days to appoint an executive management representative who shall negotiate in good faith to resolve the Dispute.

8.3.4 Exercise of Remedies at Law or in Equity. If the Parties' executive management representatives are unable to resolve the Dispute within thirty (30) days of their appointment, then each Party shall be free to pursue any remedies available to it and to take any action in law or equity that it believes necessary or convenient in order to enforce its rights or cause to be fulfilled any of the obligations or agreements of the other Party.

8.4 LG&E/KU Rights Under FPA Unaffected. Nothing in this Agreement is intended to limit or abridge any rights that LG&E/KU may have to file or make application before FERC under Section 205 of the FPA to revise any rates, terms or conditions of the OATT or any other FPA jurisdictional agreement.

8.5 Reliability Coordinator Rights Under the TVA Act and FPA Unaffected. Nothing in this Agreement is intended to limit or abridge any rights that the Reliability Coordinator may have under the TVA Act or the FPA, nor to require the Reliability Coordinator to violate the area limitations set forth in the TVA Act.

8.6 Statute of Limitations; Continued Performance. The Parties agree to waive the applicable statute of limitations during the period of time that the Parties are seeking to resolve a Dispute pursuant to Sections 8.3.2 and 8.3.3, and the statute of limitations shall be tolled for such period. The Parties shall continue to perform their obligations under this Agreement during the resolution of a Dispute.

Section 9 - Insurance.

9.1 Requirements. The Reliability Coordinator shall provide and maintain during the Term insurance coverage in the form and with minimum limits of liability as specified below, unless otherwise agreed to by the Parties.

9.1.1 Worker's compensation insurance in accordance with the Federal Employees Compensation Act (FECA).

9.1.2 Commercial general liability or equivalent insurance with a combined single limit of not less than $1,000,000 per occurrence. Such insurance shall include products/completed operations liability, owners protective, blanket contractual liability, personal injury liability and broad form property damage.

9.2 Insurance Matters. All insurance coverages required pursuant to Section 9.1 shall (a) be provided by insurance companies that have a Best Rating of A or higher, (b) provide that LG&E/KU is an additional insured (other than the workers' compensation insurance), (c) provide that LG&E/KU will receive at least thirty (30) days written notice from the insurer prior to the cancellation or termination of or any material change in any such insurance coverages, and (d) include waivers of any right of subrogation of the insurers thereunder against LG&E/KU. Certificates of insurance evidencing that the insurance required by Section 9.1 is in force shall be delivered by the Reliability Coordinator to LG&E/KU prior to the Effective Date.

9.3 Compliance. The Reliability Coordinator shall not commence performance of any Functions until all of the insurance required pursuant to Section 9.1 is in force, and the necessary documents have been received by LG&E/KU pursuant to Section 9.2. Compliance with the insurance provisions in Section 9 is expressly made a condition precedent to the obligation of LG&E/KU to make payment for any Functions performed by the Reliability Coordinator under this Agreement. The minimum insurance requirements set forth above shall not vary, limit or waive the Reliability Coordinator's legal or contractual responsibilities or liabilities under this Agreement.

Section 10 - Confidentiality.

10.1 Definition of Confidential Information. For purposes of this Agreement, "Confidential Information" shall mean, in respect of each Party, all activities by such Party and information and documentation of such Party, whether disclosed to or accessed by the other Party, in each case, in connection with this Agreement; provided, however, that the term "Confidential Information" shall not include information that: (a) is independently developed by the recipient, as demonstrated by the recipient's written records, without violating the disclosing Party's proprietary rights; (b) is or becomes publicly known (other than through unauthorized disclosure); (c) is disclosed by the owner of such information to a third party free of any obligation of confidentiality; (d) is already known by the recipient at the time of disclosure, as demonstrated by the recipient's written records, and the recipient has no obligation of confidentiality other than pursuant to this Agreement or any confidentiality agreements between the Parties entered into before the Effective Date; or (e) is rightfully received by a Party free of any obligation of confidentiality.

10.2 Protection of Confidential Information. All Confidential Information shall be held in confidence by the recipient to the same extent and in at least the same manner as the recipient protects its own confidential information, and such Confidential Information shall be used only for purposes of performing obligations under this Agreement. Except as otherwise provided in Section 10.4, neither Party shall disclose, publish, release, transfer or otherwise make available Confidential Information of, or obtained from, the other Party in any form to, or for the use or benefit of, any person or entity without the disclosing Party's prior written consent. Each Party shall be permitted to disclose relevant aspects of the other Party's Confidential Information to its officers, directors, agents, professional advisors, contractors, subcontractors and employees and to the officers, directors, agents, professional advisors, contractors, subcontractors and employees of its Affiliates, to the extent that such disclosure is reasonably necessary for the performance of its duties and obligations or the determination, preservation or exercise of its rights and remedies under this Agreement; provided, however, that the recipient shall take all reasonable measures to ensure that Confidential Information of the disclosing Party is not disclosed or duplicated in contravention of the provisions of this Agreement by such officers, directors, agents, professional advisors, contractors, subcontractors and employees. The obligations in this Section 10 shall not restrict any disclosure pursuant to any local, state or federal governmental agency or authority if such release is necessary to comply with applicable laws, governmental regulations or orders of regulatory bodies or courts; provided that, other than in respect of disclosures pursuant to Section 10.4, the recipient shall give prompt notice to the disclosing Party in reasonable time to exercise whatever legal rights the disclosing Party may have to prevent or limit such disclosure. Further, the recipient shall cooperate with the disclosing Party in preventing or limiting such disclosure.

10.3 NERC Data Confidentiality Agreement. In addition to, and not in limitation of, the confidentiality restrictions in Section 10.2, each Party shall sign the NERC Data Confidentiality Agreement and shall treat all Confidential Information as transmission operations and transmission system information pursuant to the NERC Data Confidentiality Agreement.

10.4 FERC Requests for Confidential Information. Notwithstanding anything in this Agreement to the contrary, if FERC or its staff, during the course of an investigation or otherwise, requests information from the Reliability Coordinator related to services provided by the Reliability Coordinator to LG&E/KU that the Reliability Coordinator is otherwise required to maintain in confidence pursuant to this Agreement, the Reliability Coordinator shall provide the requested information to FERC or its staff within the time provided for in the request for information. In providing such information to FERC or its staff, the Reliability Coordinator shall, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. The Reliability Coordinator shall notify LG&E/KU when it is notified by FERC or its staff that a request for public disclosure of, or decision to publicly disclose, confidential information has been received, at which time either the Reliability Coordinator or LG&E/KU may respond before such information is made public, pursuant to 18 C.F.R. § 388.112.

Section 11 - Force Majeure.

11.1 Neither Party shall be liable to the other Party for any failure or delay of performance hereunder due to causes beyond such Party's reasonable control, which by the exercise of reasonable due diligence such Party is unable, in whole or in part, to prevent or overcome (a "Force Majeure"), including acts of God, act of the public enemy, fire, explosion, vandalism, cable cut, storm or other catastrophes, weather impediments, national emergency, insurrections, riots, wars or any law, order, regulation, direction, action or request of any government or authority or instrumentality thereof. Neither Party shall be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure, except for the obligation to pay any amount when due, provided that the affected Party:

11.1.1 gives notice to the other Party of the event or circumstance giving rise to the event of Force Majeure;

11.1.2 affords the other Party reasonable access to information about the event or circumstances giving rise to the event of Force Majeure;

11.1.3 takes commercially reasonable steps to restore its ability to perform its obligations hereunder as soon as reasonably practicable, provided that the affected Party shall not be obligated to take any steps that are not otherwise in accordance with Good Utility Practice; and

11.1.4 exercises commercially reasonable efforts to perform its obligations hereunder.

Section 12 - Reporting; Audit.

12.1 Reporting. The Reliability Coordinator shall make regular reports to FERC and LG&E/KU's retail regulators as may be required by applicable law and regulations or as may be requested by such authorities.

12.2 Books and Records. The Reliability Coordinator shall maintain full and accurate books and records pertinent to this Agreement, and the Reliability Coordinator shall maintain such books and records for three (3) years following the expiration or early termination of this Agreement or longer if necessary to resolve a pending Dispute. LG&E/KU will have the right, at reasonable times and under reasonable conditions, to inspect and audit, or have an independent third party inspect and audit, the Reliability Coordinator's operations and books to (a) ensure compliance with this Agreement, (b) verify any cost claims or other amounts due hereunder, and (c) validate the Reliability Coordinator's internal controls with respect to the performance of the Functions. The Reliability Coordinator shall maintain an audit trail, including all original transaction records, of all financial and non-financial transactions resulting from or arising in connection with this Agreement as may be necessary to enable LG&E/KU or the independent third party, as applicable, to perform the foregoing activities. LG&E/KU shall be responsible for any costs and expenses incurred in connection with any such inspection or audit, unless such inspection or audit discovers that LG&E/KU was charged inappropriate or incorrect costs and expenses, in which case, the Reliability Coordinator shall be responsible for a percentage of the costs and expenses incurred in connection with such inspection or audit equal to the percentage variance by which LG&E/KU was charged inappropriate or incorrect costs and expenses. The Reliability Coordinator shall provide reasonable assistance necessary to enable LG&E/KU or an independent third party, as applicable, and shall not be entitled to charge LG&E/KU for any such assistance. Amounts incorrectly or inappropriately invoiced by the Reliability Coordinator to LG&E/KU, whether discovered prior to or subsequent to payment by LG&E/KU, shall be adjusted or reimbursed to LG&E/KU by the Reliability Coordinator within twenty (20) days of notification by LG&E/KU to the Reliability Coordinator of the error in the invoice.

12.3 Regulatory Compliance. The Reliability Coordinator shall comply with all reasonable requests by LG&E/KU to comply with Section 404 of the Sarbanes-Oxley Act and related regulatory requirements. LG&E/KU may hire, at its expense, or LG&E/KU may direct the Reliability Coordinator to hire, at LG&E/KU expense, an independent auditor to review, audit and prepare audit reports associated with the Reliability Coordinator's controls and systems relating to the Functions and LG&E/KU's financial statements and reports, in accordance with SAS No. 70, Type II. Such reports may not be required more frequently than twice per Contract Year. The Reliability Coordinator shall notify LG&E/KU prior to or at the time of any significant or material change to any internal process or financial control of the Reliability Coordinator that would or might impact the Functions performed for or on behalf of LG&E/KU or that would, or might, have a significant or material effect on such process's mitigation of risk or upon the integrity of LG&E/KU's financial reporting or disclosures and provide sufficient details of the change so as to enable LG&E/KU and/or its independent auditors to review the change and evaluate its impact on its internal controls and financial reporting. The Reliability Coordinator shall cooperate with the independent auditors and LG&E/KU to enable the preparation of the reports necessary to comply with Section 404 of the Sarbanes-Oxley Act, consistent with the other provisions of this Agreement.

Section 13 - Independent Contractor.

The Reliability Coordinator shall be and remain during the Term an independent contractor with respect to LG&E/KU, and nothing contained in this Agreement shall be (a) construed as inconsistent with that status, or (b) deemed or construed to create the relationship of principal and agent or employer and employee, between the Reliability Coordinator and LG&E/KU or to make either the Reliability Coordinator or LG&E/KU partners, joint ventures, principals, fiduciaries, agents or employees of the other Party for any purpose. Neither Party shall represent itself to be an agent, partner or representative of the other Party. Neither Party shall commit or bind, nor be authorized to commit or bind, the other Party in any manner, without such other Party's prior written consent. Personnel employed, provided or used by any Party in connection herewith will not be employees of the other Party in any respect. Each Party shall have full responsibility for the actions or omissions of its employees and shall be responsible for their supervision, direction and control.

Section 14 - Taxes.

Each Party shall be responsible for the payment of its own taxes, including taxes based on its net income, employment taxes of its employees, taxes on any property it owns or leases, and sales, use, gross receipts, excise, value-added or other transaction taxes.

Section 15 - Notices.

15.1 Notices. Except as otherwise specified herein, any notice required or authorized by this Agreement shall be deemed properly given to a Party when sent to its designated representative by facsimile or other electronic means (with a confirmation copy sent by United States mail, first-class postage prepaid), by hand delivery, or by United States mail, first-class postage prepaid. The Parties' designated representatives are as follows:

If to LG&E/KU:

Louisville Gas and Electric Company
220 West Main St.
Louisville, Kentucky 40202
Facsimile: (502) 627-4002

And

Kentucky Utilities Company
220 West Main St.
Louisville, Kentucky 40202
Facsimile: (502) 627-4002

If to the Reliability Coordinator:

Tennessee Valley Authority
1101 Market Street, PCC 2A
Chattanooga, Tennessee 37402-2801
Facsimile: (423) 697-4120

15.2 Changes. Either Party may, from time to time, change the names, addresses, facsimile numbers or other notice information set out in Section 15.1 by notice to the other Party in accordance with the requirements of Section 15.1.

Section 16 - Key Personnel; Work Conditions.

16.1 Key Personnel. All Key Personnel shall be properly certified and licensed, if required by law, and be qualified and competent to perform the Functions. The Reliability Coordinator shall provide LG&E/KU prior written notice of the replacement of any Key Personnel.

16.2 Conduct of Key Personnel and Reporting. The Reliability Coordinator agrees to require that the Key Personnel comply with the Reliability Coordinator's employee code of conduct, a current copy of which has been provided to LG&E/KU. The Reliability Coordinator may amend its employee code of conduct at any time, provided that the Reliability Coordinator shall promptly provide the LG&E/KU Contract Manager with a copy of the amended employee code of conduct. If any Key Personnel commits fraud or engages in material violation of the Reliability Coordinator's employee code of conduct, the Reliability Coordinator shall promptly notify LG&E/KU as provided above and promptly remove any such Key Personnel from the performance of the Functions.

16.3 Personnel Screening. The Reliability Coordinator shall be responsible for conducting, in accordance with applicable law (including the Fair Credit Reporting Act, The Fair and Accurate Credit Transactions Act, and Title VII of the Civil Rights Act of 1964), adequate pre-deployment screening of the Key Personnel prior to commencing performance of the Functions. By deploying Key Personnel under this Agreement, the Reliability Coordinator represents that it has completed the Screening Measures (as defined below) with respect to such Key Personnel. To the extent permitted by applicable law, the term "Screening Measures" shall include, at a minimum, a background check including: (a) a Terrorist Watch Database Search; (b) a Social Security Number trace; (c) motor vehicle license and driving record check; and (d) a criminal history check, including, a criminal record check for each county/city and state/country in the employee's residence history for the maximum number of years permitted by law, up to seven (7) years. Unless prohibited by law, if, prior to or after assigning a Key Personnel to perform the Functions, the Reliability Coordinator learns of any information that the Reliability Coordinator considers would adversely affect such Key Personnel's suitability for the performance of the Functions (including based on information discovered from the Screening Measures), the Reliability Coordinator shall not assign the Key Personnel to the Functions or, if already assigned, promptly remove such Key Personnel from performing the Functions and immediately notify LG&E/KU of such action.

16.4 Security. LG&E/KU shall have the option of barring from LG&E/KU's property any Key Personnel whom LG&E/KU determines is not suitable in accordance with the applicable laws pursuant to Sections 16.1 through 16.3.

Section 17 - Miscellaneous Provisions.

17.1 Governing Law. This Agreement and the rights and obligations of the Parties hereunder shall be governed by and construed in accordance with applicable state and federal laws, without regard to the laws requiring the applicability of the laws of another jurisdiction.

17.2 Amendment. This Agreement shall not be varied or amended unless such variation or amendment is agreed to by the Parties in writing.

17.3 Assignment. Neither Party shall sell, assign, or otherwise transfer any or all of its respective rights hereunder, or delegate any or all of its respective obligations under this Agreement.

17.4 No Third Party Beneficiaries. Nothing in this Agreement is intended to confer any benefits upon any person or entity not a Party to this Agreement. This Agreement is made solely for the benefit of the Parties and nothing herein shall be construed as a stipulation for the benefit of others, and no third party shall be entitled to enforce this Agreement against any Party hereto.

17.5 Waivers. No waiver of any provision of this Agreement shall be effective unless it is signed by the Party against which it is sought to be enforced. The delay or failure by either Party to exercise or enforce any of its rights under this Agreement shall not constitute or be deemed a waiver of that Party's right thereafter to enforce those rights, nor shall any single or partial exercise of any such right preclude any other or further exercise thereof or the exercise of any other right.

17.6 Severability; Renegotiation. The invalidity or unenforceability of any portion or provision of this Agreement shall in no way affect the validity or enforceability of any other portion or provision herein. If any provision of this Agreement is found to be invalid, illegal or otherwise unenforceable, the same shall not affect the other provisions hereof or the whole of this Agreement and shall not render invalid, illegal or unenforceable this Agreement or any of the remaining provisions of this Agreement. If any provision of this Agreement or the application thereof to any person, entity or circumstance, is held by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, or if a modification, condition or other change to this Agreement is imposed by a court or regulatory authority of competent jurisdiction which materially affects the benefits or obligations of the Parties, then the Parties shall in good faith negotiate such amendment or amendments to this Agreement as will restore the relative benefits and obligation of the Parties immediately prior to such holding, modification or condition. If such negotiations are unsuccessful, then either Party may terminate this Agreement pursuant to Section 4.5.1.

17.7 Representations and Warranties. Each Party represents and warrants to the other Party as of the Execution Date and the Effective Date as follows:

17.7.1 Organization. It is duly organized, validly existing and in good standing under the laws of the State in which it was organized or applicable Federal law, and has all the requisite power and authority to own and operate its material assets and properties and to carry on its business as now being conducted and as proposed to be conducted under this Agreement.

17.7.2 Authority. It has the requisite power and authority to execute and deliver this Agreement and, subject to the procurement of applicable regulatory approvals, to perform its obligations under this Agreement. The execution and delivery of this Agreement by it and the performance of its obligations under this Agreement have been duly authorized by all necessary corporate action required on its part.

17.7.3 Binding Effect. Assuming the due authorization, execution and delivery of this Agreement by the other Party, this Agreement constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency or other similar applicable laws affecting creditors' rights generally, and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

17.7.4 Regulatory Approval. It has obtained or will obtain by the Effective Date, any and all approvals of, and acceptances for filing by, and has given or will give any notices to, any applicable federal or state authority, that are required for it to execute, deliver, and perform its obligations under this Agreement.

17.7.5 No Litigation. There are no actions at law, suits in equity, proceedings, or claims pending or, to its knowledge, threatened against it before or by any federal, state, foreign or local court, tribunal, or governmental agency or authority that might materially delay, prevent, or hinder the performance by such entity of its obligations hereunder.

17.7.6 No Violation or Breach. The execution, delivery and performance by it of its obligations under this Agreement do not and shall not: (a) violate its organizational documents; (b) violate any applicable law, statute, order, rule, regulation or judgment promulgated or entered by any applicable federal or state authority, which violation could reasonably be expected to materially adversely affect the performance of its obligations under this Agreement; or (c) result in a breach of or constitute a default of any material agreement to which it is a party.

17.8 Further Assurances. Each Party agrees that it shall execute and deliver such further instruments, provide all information, and take or forbear such further acts and things as may be reasonably required or useful to carry out the purpose of this Agreement and are not inconsistent with the provisions of this Agreement.

17.9 Entire Agreement. This Agreement and the Attachments hereto set forth the entire agreement between the Parties with respect to the subject matter hereof, and supersede all prior agreements, whether oral or written, related to the subject matter of this Agreement, including that certain Reliability Coordinator Agreement, dated as of January 10, 2006, between the Parties. The terms of this Agreement and the Attachments hereto are controlling, and no parole or extrinsic evidence, including to prior drafts and drafts exchanged with any third parties, shall be used to vary, contradict or interpret the express terms, and conditions of this Agreement.

17.10 Good Faith Efforts. Each Party agrees that it shall in good faith take all reasonable actions necessary to permit it and the other Party to fulfill their obligations under this Agreement. Where the consent, agreement or approval of any Party must be obtained hereunder, such consent, agreement or approval shall not be unreasonably withheld, delayed or conditioned. Where a Party is required or permitted to act, or omit to act, based on its opinion or judgment, such opinion or judgment shall not be unreasonably exercised. To the extent that the jurisdiction of any federal or state authority applies to any part of this Agreement or the transactions or actions covered by this Agreement, each Party shall cooperate with the other Party to secure any necessary or desirable approval or acceptance of such authorities of such part of this Agreement or such transactions or actions.

17.11 Time of the Essence. With respect to all duties, obligations and rights of the Parties, time shall be of the essence in this Agreement.

17.12 Interpretation. Unless the context of this Agreement otherwise clearly requires:

17.12.1 all defined terms in the singular shall have the same meaning when used in the plural and vice versa;

17.12.2 the terms “hereof,” “herein,” “hereto” and similar words refer to this entire Agreement and not to any particular Section, Attachment or any other subdivision of this Agreement;

17.12.3 references to "Section" or "Attachment" refer to this Agreement, unless specified otherwise;

17.12.4 references to any law, statute, rule, regulation, notification or statutory provision shall be construed as a reference to the same as it applies to this Agreement and may have been, or may from time to time be, amended, modified or re-enacted;

17.12.5 references to "includes," "including" and similar phrases shall mean "including, without limitation;"

17.12.6 the captions, section numbers and headings in this Agreement are included for convenience of reference only and shall not in any way affect the meaning or interpretation of this Agreement;

17.12.7 "or" may not be mutually exclusive, and can be construed to mean "and" where the context requires there to be a multiple rather than an alternative obligation; and

17.12.8 references to a particular entity include such entity's successors and assigns to the extent not prohibited by this Agreement.

17.12.9 any capitalized terms used in this Agreement, including the Appendices, that are not defined in this Agreement or in the Appendices, shall have the meaning established in the applicable NERC documentation.

17.13 Joint Effort. Preparation of this Agreement has been a joint effort of the Parties and the resulting document shall not be construed more severely against one of the Parties than against the other and no provision in this Agreement is to be interpreted for or against any Party because that Party or its counsel drafted such provision. Each Party acknowledges that in executing this Agreement its has relied solely on its own judgment, belief and knowledge, and such advice as it may have received from its own counsel, and it has not been influenced by any representation or statement made by the other Party or its counsel not contained in this Agreement.

17.14 Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument, binding upon LG&E/KU and the Reliability Coordinator, notwithstanding that LG&E/KU and the Reliability Coordinator may not have executed the same counterpart.

Section 18 - Confidential Critical Infrastructure Information Protection. Notwithstanding any other applicable confidentiality provisions in this RC Agreement including Section 10 above, the following provisions of this Section 18 shall apply with respect to LG&E/KU's Protected Assets and Information. "LG&E/KU's Protected Assets and Information" is defined as: (i) LG&E/KU's Critical Cyber Assets, (ii) LG&E/KU's Cyber Assets used in access control and monitoring of Company's Electronic Security Perimeter(s), (iii) LG&E/KU's Cyber Assets that authorize or log access to LG&E/KU's

Physical Security Perimeter(s) or (iv) any information relating to LG&E/KU's Critical Cyber Assets, including, without limitation, operational procedures, Critical Asset lists, Critical Cyber Asset lists, network topology or similar diagrams, floor plans of computer centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, security configuration information, and any other confidential information relating to the reliability or operability of the Bulk Electric System and information generated or otherwise developed by the Reliability Coordinator in connection with its performance of the Reliability Coordinator functions that constitute or are otherwise related to LG&E/KU's Protected Assets and Information (collectively, "Confidential Critical Infrastructure Information"). The Reliability Coordinator shall not disclose any Confidential Critical Infrastructure Information (which will be clearly marked or otherwise identified by LG&E/KU as Confidential Critical Infrastructure Information) to any person or entity, except strictly on a need-to-know basis, and shall take all necessary actions to protect the Confidential Critical Infrastructure Information, including, without limitation, ensuring that appropriate electronic and/or password access controls are in place if such Confidential Critical Infrastructure Information is stored on shared drives or systems, encrypting all such information stored on laptops or removable media (such as a USB drive), and maintaining any such hard copy information in a secure, locked storage container and not permitting any unauthorized individual to view, handle or possess such information. The Reliability Coordinator shall provide to LG&E/KU a list of all the Reliability Coordinator employees, subcontractors or other persons associated with the Reliability Coordinator with access to any Confidential Critical Infrastructure Information when and as requested by LG&E/KU. The Reliability Coordinator will provide notification by contacting the LG&E/KU's NERC Compliance representative identified below immediately upon becoming aware that it has disclosed any Confidential Critical Infrastructure Information in violation of this Section 18. The Reliability Coordinator shall ensure that each recipient of any Confidential Critical Infrastructure Information understands and complies with the requirements to protect Confidential Critical Infrastructure Information from inappropriate disclosure as set forth in this Section 18. Notwithstanding anything to the contrary in the Contract, with respect to any Confidential Critical Infrastructure Information, the restrictions set forth in this Section 18 shall remain in effect indefinitely from the date such Confidential Critical Infrastructure Information was first disclosed to or obtained or discovered by the Reliability Coordinator. The Reliability Coordinator shall, upon request and as directed by LG&E/KU, promptly return to LG&E/KU, or otherwise properly dispose of, any and all Confidential Critical Infrastructure Information that is in the possession of the Reliability Coordinator or any of its employees or subcontractors.

The parties have caused this Reliability Coordinator Agreement to be executed by their duly authorized representatives as of the dates shown below.

LOUISVILLE GAS AND ELECTRIC COMPANY

/s/ Tom Jessee

Name: Tom Jessee
Title: Vice President, Transmission
Date: 8/25/14

KENTUCKY UTILITIES COMPANY

/s/ Tom Jessee

Name: Tom Jessee
Title: Vice President, Transmission
Date: 8/25/14

TENNESSEE VALLEY AUTHORITY

/s/ Timothy E. Ponseti

Name: Timothy E. Ponseti
Title: Vice President, Transmission Operations & Power Supply
Date: 8-25-2014

ATTACHMENT A
TO THE RELIABILITY COORDINATOR AGREEMENT

DESCRIPTION OF THE PRIMARY FUNCTIONS

The Reliability Coordinator is responsible for bulk transmission reliability and power supply reliability functions. Bulk transmission reliability functions include reliability analysis, loading relief procedures, re-dispatch of generation and ordering curtailment of transactions and/or load.
Power supply reliability functions include monitoring Balancing Authority Area performance and ordering the Balancing Authority to take actions, including load curtailment and increasing/decreasing generation in situations where an imbalance between generation and load places the system in jeopardy. The procedures to be followed by the Reliability Coordinator shall be consistent with those of NERC and are spelled out in the NERC Approved Reliability Plan for the TVA Reliability Coordination Area and TVA Standard Procedures and Policies.

I. Reliability Coordinator General Functions:

The Reliability Coordinator shall perform the following functions:

a) Serving as NERC designated reliability coordinator and represent the TVA Reliability Area at the NERC and Regional Reliability Council level.

b) Implementing applicable NERC and regional reliability criteria initiatives, such as maintaining a connection to NERC's Interregional Security Network ("ISN"), day-ahead load-flow analysis, transmission loading relief procedures, and information exchange.

c) Developing and coordinating with the Reliability Coordination Advisory Committee ("RCAC") new Reliability Coordinator Procedures and revisions to existing Reliability Coordinator Procedures.

d) Exchanging timely, accurate, and relevant Transmission System information with LG&E/KU, the ITO, and with other reliability coordinators.

e) Developing and maintaining system models and tools needed to perform analysis needed to develop operational plans.

f) Coordinating with neighboring reliability coordinators and other operating entities as appropriate to ensure regional reliability.

g) All other reliability coordinator functions as required for compliance with applicable NERC Reliability Standards and Regional Reliability Council standards, as the same may be amended or modified from time to time.

II. Real-time Operations:

A. Reliability Coordinator Functions:

The Reliability Coordinator shall perform the following functions:

a) Monitoring, analyzing, and coordinating the reliability of LG&E/KU's facilities and interfaces with other Balancing Authorities, Transmission Operators, and other reliability coordinators.

b) Performing analyses to develop an evaluation of system conditions. LG&E/KU will provide necessary information (e.g., outages and transactions) and Transmission System conditions, as applicable, to the Reliability Coordinator in accordance with applicable NERC Reliability Standards. The results of these analyses will be provided to LG&E/KU and neighboring reliability coordinators in accordance with applicable NERC Standards and Regional Reliability Council Standards.

c) Determining, directing, and documenting appropriate actions to be taken by LG&E/KU, the ITO and Reliability Coordinator in accordance with the NERC Reliability Standards, including curtailment of transmission service or energy schedules, re-dispatch of generation and load shedding as necessary to alleviate facility overloads and abnormal voltage conditions, and other circumstances that affect interregional bulk power reliability.

d) Coordinating transmission loading relief and voltage correction actions with LG&E/KU and with other reliability coordinators.

B. LG&E/KU Responsibilities:

LG&E/KU shall have the following responsibilities:

a) Ensuring appropriate telemetry and providing Reliability Coordinator real-time operational information for monitoring.

b) Receiving from the Reliability Coordinator all reliability alerts for TVA Reliability Area and neighboring reliability coordinators.

c) Following Reliability Coordinator directives for corrective actions (e.g., curtailments or load shedding) during system emergencies or to implement TLR procedures.

d) Receiving from Reliability Coordinator all notices regarding Transmission System limitations or other reliability issues, as appropriate.

III. Forward Operations:

A. Reliability Coordinator Functions:

The Reliability Coordinator shall perform the following functions:

a) Performing analyses and develop an evaluation of the expected next-day Transmission System operations. The results of these analyses shall be provided to LG&E/KU, the ITO and neighboring reliability coordinators in accordance with applicable NERC Reliability Standards and Regional Reliability Council Standards.

b) Performing analysis of planned transmission and generation outages and coordination of outages with NERC, participants in reliability coordination agreements, and other reliability coordinators as appropriate and as required by NERC. This entails analysis and coordination of planned outages which are beyond next day and intra-day outages.

c) Analyzing and approving all planned maintenance schedules on facilities 100kV and above and planned maintenance of generation facilities submitted by LG&E/KU in conjunction with other work on the regional transmission grid to determine the impact of LG&E/KU's planned maintenance schedule on the reliability of the facilities under TVA's purview as Reliability Coordinator, and the purview of neighboring reliability coordinators, and any other relevant effects; and coordinate impacts on available transfer capability with the ITO.

d) Coordinating, as required by either NERC or other agreements, planned maintenance schedules with all adjacent reliability coordination areas and/or Balancing Authority Areas and Transmission Providers; as well as the ITO.

B. <u>LG&E/KU Responsibilities</u>:

LG&E/KU shall have the following responsibilities:

a) Providing generation-related information (e.g., outages and transactions) and expected Transmission System conditions (e.g., transmission facility outages and transactions), as applicable, to the Reliability Coordinator for the next-day operation in accordance with applicable NERC Reliability Standards and Regional Reliability Council standards.

b) Submitting facility ratings and operational data for all generators and transmission facilities in the LG&E/KU footprint.

c) Coordinating with the ITO and submitting to the Reliability Coordinator generation dispatch information for the LG&E/KU footprint and following Reliability Coordinator directives regarding dispatch adjustments to mitigate congestion.

d) Submitting to the Reliability Coordinator generation operation plans and commitments for reliability analysis.

e) Submitting to the Reliability Coordinator transmission maintenance plans for reliability analysis.

f) Following Reliability Coordinator directives to revise transmission maintenance plans as required to ensure grid reliability.

g) Receiving from Reliability Coordinator all notices regarding reliability analyses for the TVA Reliability Area as well as neighboring reliability coordinators.

h) Representing LG&E/KU on the RCAC and in all RCAC deliberations.

IV. Regional Congestion Management

For the purposes of this section IV, capitalized terms will have the definitions used in the Congestion Management Process ("CMP"), unless otherwise noted in this section IV.

A. Reliability Coordinator Functions:

The following functions to be performed by the Reliability Coordinator shall be performed in conjunction with the functions to be performed by the Independent Transmission Operator under the Independent Transmission Organization Agreement and will fully incorporate the LG&E/KU operations into the procedures and protocols governing other facilities in the Reliability Coordinator's Reliability Area in accordance with the CMP:

a) Identifying Coordinated Flowgates and determination of flowgates requiring Reciprocal Coordination (twice annually).

b) Performing Historic Firm Flow Calculations -- implement transmission service reservation set and designated resources provided by LG&E/KU for established freeze date; calculate historic firm flow values and ratios for all coordinated flowgates on LG&E/KU's system (bi-annually).

c) Developing reciprocal coordination agreements that establish how each Operating Entity will consider its own flowgates as well as the usage of other Operating Entities when it determines the amount of flowgate or constraint capacity remaining. This process will include both operating horizon determination as well as forward looking capacity allocation.

d) Implementing AFC Process -- determine AFC attribute requirements; obtain NNL Impact Data; implement Allocation Calculation Process; implement AFC calculation process.

e) The Reliability Coordinator will provide the ITO flowgate AFCs on an hourly basis and flowgate allocations on a daily basis.

B. <u>LG&E/KU Responsibilities</u>:

LG&E/KU is obligated to uphold the terms and conditions of the CMP, and providing the Reliability Coordinator with the information and support it needs in order to carry out its duties as LG&E/KU 's Reliability Coordinator. LG&E/KU shall have the following responsibilities. LG&E/KU will be responsible for coordinating with the ITO and providing

Transmission System data to the Reliability Coordinator including, but not limited to:

Operating information:

(i) Transmission Service Reservations;
(ii) Load forecast requirements;
(iii) Flowgates requirements;
(iv) AFC data requirements;
(v) PSSE Models Requirements;
(vi) Designated Network Resources requirements;
(vii) Jointly owned units;
(viii) Dynamic schedules;
(ix) NNL allocations requirements; and,
(x) NNL Evaluator Requirements.

Projected operating information:

(i) Unit commitment/merit order;
(ii) Firm purchase and sales (including grandfathered agreements);
(iii) Independent power producer information including current operating level, projected operating levels, Scheduled Outage start and end dates;
(iv) Planned and actual operational start-up dates for any permanently added, removed, or significantly altered transmission segments; and
(v) Planned and actual start-up testing and operational start-up dates for any permanently added, removed, or significantly altered generation units.

C. <u>ITO Responsibilities</u>:

The ITO shall have the following responsibilities in support of the Congestion Management Process (“CMP”):

a) Providing to the Reliability Coordinator all transmission facility plans and facility upgrade schedules.

b) Providing to the Reliability Coordinator the status of all transmission service requests and all new transmission service agreements.

c) Receiving from the Reliability Coordinator all flowgate AFCs on an hourly basis and flowgate allocations on a daily basis.

d) Converting flowgate information provided by the Reliability Coordinator to ATC values for posting on OASIS and for analyzing TSRs.

e) Implementing CMP business rules for AFC vs. ASTFC.

f) Honoring all AFC allocations and AFC over-rides from other CMP participants in the evaluation and granting of transmission service.

V. <u>Reliability Coordination</u>

A. <u>Reliability Coordinator Functions</u>:

The Reliability Coordinator will ensure a long-term (one year and beyond) plan is available for adequate resources and transmission within the TVA Reliability Area. The Reliability Coordinator will integrate the Annual Plan provided by the ITO with plans of other operating entities in the Reliability Coordination Area and assess the plans to ensure those plans meet reliability standards. The Reliability Coordinator will advise the ITO of solutions to plans that do not meet those standards. The Reliability Coordinator will then coordinate the Reliability Area Plan with those of neighboring reliability coordinators and Planning Coordinators to ensure wide-area grid reliability.

These functions include:

a) Integrating the transmission and resource (demand and capacity) system models provided by the ITO with those of other Reliability Coordinator Area operating entities to ensure Transmission System reliability and resource adequacy.

b) Applying methodologies and tools to assess and analyze the Transmission System's expansion plans and the resource adequacy plans.

c) Collecting all information and data required for modeling and evaluation purposes.

d) Integrating and verifying that the respective plans of the Resource Planners and Transmission Planners within the TVA Reliability Area meet reliability standards.

e) Coordinating the Reliability Coordinator Area plan with neighboring Reliability Coordinators for review, as appropriate.

f) Integrating the Reliability Coordinator Area plan with neighboring Planning Coordinators/reliability coordinators' plans to provide a broad multi-regional bulk system planning view.

B. <u>LG&E/KU Responsibilities</u>:

LG&E/KU shall have the following responsibilities:

a) Providing to the Reliability Coordinator demand and energy end-use customer forecasts, capacity resources, and demand response programs.

b) Providing to the Reliability Coordinator generator unit performance characteristics and capabilities.

c) Providing to Reliability Coordinator long-term capacity purchases and sales.

ATTACHMENT B

DIVISION OF RESPONSIBILITIES FOR THE PLANNING FUNCTION

Overview

This Attachment B to the Reliability Coordinator Agreement is designed to provide a division of responsibilities between LG&E/KU, the ITO and the Reliability Coordinator. Long-term Transmission Planning for LG&E/KU's footprint will be conducted as an iterative process as follows: 1) LG&E/KU will develop the long-term Annual Transmission Plan ("Annual Plan") and submit the Annual Plan to the ITO for initial approval; 2) The ITO will review and conduct an engineering assessment of the Annual Plan; and if it is approved, the ITO will submit the Annual Plan to the Reliability Coordinator; 3) The Reliability Coordinator will conduct a regional assessment of the Annual Plan, subject to the conditions below; 4) The Reliability Coordinator will submit any changes based on its regional assessment to the ITO for final review and approval. The ITO will ensure that transmission planning on the Transmission Owner's system is done on an independent, non-discriminatory basis. This process is further detailed below.

1. Plan Development by LG&E/KU

LG&E/KU will be responsible for the following tasks:

1.1 System Models for Transmission Planning. LG&E/KU will develop and maintain all transmission and resource (demand and capacity) system models, to evaluate Transmission System performance and resource adequacy. As part of these duties LG&E/KU is responsible for:

1.1.1 Creating the Base Case Model for the Transmission System. This Model will include all existing long-term, firm uses of the Transmission System, including: (i) Network Integration Transmission Service; (ii) firm transmission service for LG&E/KU's Native Load; (iii) Long-Term Point-to-Point Transmission Service; and (iv) firm transmission service provided in accordance with grandfathered agreements. The Base Case Model will be developed pursuant to the modeling procedures used in developing the NERC multi-regional and Reliability*First* regional models.

1.1.2 Providing the Base Case Model to the ITO for review and approval according to the iterative process outlined in the overview to this Attachment B.

1.1.3 Maintaining other transmission models including, but not limited to steady-state, dynamic and short circuit models.

1.2 Assess, develop, and document Resource and Transmission Expansion

plans. LG&E/KU will assess, develop, and document Resource and Transmission Expansion plans including the Annual Plan. These plans include the following responsibilities:

1.2.1 Maintaining and apply methodologies and appropriate tools for the development, analysis and simulation of the Transmission System in the assessment and development of transmission expansion plans and the analysis and development of resource adequacy plans.

1.2.2 Developing a long-term (generally one year and beyond) plan for the reliability (adequacy) of the Transmission System.

1.2.3 Defining system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability standards.

1.2.4 Developing and report, as appropriate, on the Annual Plan for assessment and compliance with reliability standards.

1.2.5 Monitoring and report, as appropriate, its Annual Plan implementation.

1.3 **Information**. LG&E/KU will define, collect and develop information required for planning purposes, including:

1.3.1 **Transmission facility characteristics and ratings.** Collect and maintain specific transmission information regarding characteristics of transmission facilities, lines, equipment, and methodologies, for determining the appropriate thermal ratings of circuits and transformers, including information on transmission line design temperature, voltage and stability limits and other transformer test data.

1.3.2 **Demand and energy end-use customer forecasts, capacity resources, and demand response programs.** Including:

i. Load forecasts for all existing delivery points for the following ten years, including transmission (wholesale and retail) connected substations and distribution substations, and coincident and noncoincident peak demands and power factor at each delivery point;

ii. Plans for new delivery points for the following ten years;

iii. Resource plans for the following 10 years;

iv. Expectations for market access to on- and off-system generation resources;

v. All planned on-system distributed generation resources; and

vi. Information on all interruptible loads.

1.3.3 **Generator unit performance characteristics and capabilities.** LG&E/KU shall provide the ITO with all necessary data, information, and applicable requirements that govern the operation of any generating facilities interconnected with the Transmission System, as the ITO may require for performance of its various functions. LG&E/KU shall submit and coordinate generator unit schedules as necessary to permit the ITO to assess transmission transfer capability and to permit the Reliability Coordinator to assess transmission reliability. LG&E/KU shall submit, on an annual basis, data concerning projected loads, designated network resources, generation and transmission maintenance schedules, and other such operating data as the ITO may require for performance its various functions.

1.3.4 **Long-term capacity purchases and sales**. LG&E/KU will maintain a list of all long-term capacity purchases and sales and include this information in its model development and the Annual Plan.

2 ITO Review and Assessment

The ITO will be responsible for the following tasks:

2.1 Independently reviewing and approving LG&E/KU's Planning Guidelines. If the ITO concludes that additional explanatory detail is required, LG&E/KU will modify the appropriate business practice documents to include the additional detail. The ITO will ensure that the final versions of the Planning Criteria are posted on OASIS;

2.2 Reviewing and approving LG&E/KU's Base Case Model; reviewing, evaluating, and commenting on the Annual Plan as developed by LG&E/KU. This review and evaluation will be based on all applicable planning criteria and statewide or multi-state transmission planning requirements;

2.3 Monitoring LG&E/KU's transmission facility ratings based on access to data necessary to evaluate such ratings;

2.4 Performing an Independent assessment of the Transmission System using the Planning Guidelines and the Base Case Model. As part of this assessment, the ITO will independently evaluate whether: (i) LG&E/KU's Annual Plan complies with the Planning Guidelines and the Base Case Model; and (ii) whether there are upgrade projects in the Annual Plan that are not necessary to meet the Planning Guidelines and the Base Case Model;

2.5 Holding a Transmission Planning Conference to gather input and consider the planning process and LG&E/KU's Annual Plan; and

2.6 Providing LG&E/KU with its conclusions regarding the reliability assessment and evaluation of the Annual Plan, including any outstanding issues that the ITO believes LG&E/KU should address. LG&E/KU will have the opportunity to review the ITO's conclusions and may submit a revised Annual Plan and supporting documentation to the ITO to address any outstanding issues. Once the Annual Plan has been finalized by LG&E/KU, the ITO will submit the Annual Plan to the Reliability Coordinator for regional coordination.

3 Regional Coordination

The Reliability Coordinator will be responsible for the following tasks:

3.1 Integrating and verifying that the respective plans for the regional area meet reliability standards.

3.2 Identifying and reporting on potential Transmission System and resource adequacy deficiencies in the regional area, and provide alternate plans that mitigate these deficiencies.

3.3 Reviewing and reporting, as appropriate, on LG&E/KU's Annual Plan for assessment and compliance with reliability standards within their regional area.

3.4 Notifying impacted transmission entities within their regional area of any planned transmission changes that may impact their facilities.

3.5 Submitting Annual Plan, including any changes based on the regional coordination, to the ITO for final approval.

4 Final Review and Assessment

4.1 The ITO shall have final review and assessment of all plans. If the ITO cannot approve a plan after regional coordination, then the ITO will return the plan to LG&E/KU for further development as appropriate. The process for final approval of any previously rejected plan will follow the same iterative process as outlined above.

4.2 The ITO will post LG&E/KU's finalized Annual Plan on OASIS.

5 Implementation of Plan and Construction of Upgrades

5.1 LG&E/KU is responsible for the implementation of the Annual Plan. LG&E/KU will make a good faith effort to design, certify, and build facilities approved by the ITO in the Annual Plan.

5.2 In the case where the Reliability Coordinator or the ITO does not agree with the Annual Plan, nothing in this Attachment B shall prevent LG&E/KU from constructing those facilities it deems necessary to reliably meet its

ATTACHMENT C
TO THE RELIABILITY COORDINATOR AGREEMENT

LIST OF KEY PERSONNEL
TVA Reliability Coordination Services

August 2014

Reliability Authority & Regional Operations
Armando Rodriguez - Senior Manager, Reliability Authority & Regional Operations
Roy Mathai - Project Manager, Operations Readiness

Reliability Operations

Nathan Schweighart - Manager, Reliability Operations
Terry Williams - Specialist Reliability Analysis Operator
Julio Bolano - Specialist Reliability Analysis Operator
Richard Brent Fuller - Specialist Reliability Analysis Operator
Timothy Gleason - Specialist Reliability Analysis Operator
Donald Herring - Specialist Reliability Analysis Operator
Daniel Kehoe - Specialist Reliability Analysis Operator
Thomas Wilk - Specialist Reliability Analysis Operator
William C. Dunn - Reliability Coordinator System Operator
Kevin Grooms - Reliability Coordinator System Operator
Darrell Jones - Reliability Coordinator System Operator
Thomas C. Nance - Reliability Coordinator System Operator
Travis Rackley - Reliability Coordinator System Operator
Brent Taylor - Reliability Coordinator System Operator

Reliability Analysis
Scott Walker - Manager, Reliability Analysis
Timothy Fritch - Electrical Engineer Planning
Marshalia Green - Electrical Engineer Planning
Gary Kobet - Electrical Engineer Planning
Shaun McFarland - Electrical Engineer Planning
Charles Michael McAmis - Electrical Engineer Planning
Jonathan Prater - Electrical Engineer Planning
Matthew Scott Schebler - Electrical Engineer Planning
Joshua Shultz - Electrical Engineer Planning
Justin Baier - Engineering Intern
Ulyana Pugina - Engineering Intern

Advanced Power Applications
Gregory Dooley - Electrical Engineer Power Systems
Alden Bost Jr. - Electrical Engineer Power Systems
Joey Burke - Electrical Engineer Power Systems
Brian Scott - Electrical Engineer Power Systems
David Nordy Jr. - Electrical Engineer Power Systems
Thomas Scott - Engineering Intern
Cyril Shircel - Engineering Intern

Karlee Winkelman - Engineering Intern

EXHIBIT 1
TO THE RELIABILITY COORDINATOR AGREEMENT

LG&E and KU hereby incorporate the Baseline Congestion Management Process (Version 1.2), which is attached hereto.

obligation to serve its Transmission Customers, point-to-point, Network Integration Service, and Native Load Customers.

Document Content(s)

Rebuttal Exhibit LEB-4

FERC Approval Letter, Mar. 2, 2017

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
Louisville Gas and Electric Company
Docket No. ER17-850-000

March 2, 2017

Louisville Gas and Electric Company
Attention: Jennifer Keisling
220 West Main Street
Louisville, KY 40202

Reference: Independent Transmission Organization Agreement

Dear Ms. Keisling:

On January 25, 2017, Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) (collectively, LG&E/KU) submitted an Independent Transmission Organization Agreement between LG&E/KU as transmission owner and TranServ International, Inc. (TranServ) as the independent transmission organization.[1] Pursuant to authority delegated to the Director, Division of Electric Power Regulation-Central, under 18 C.F.R. § 375.307, the submittal in the above-referenced docket is accepted, effective September 1, 2017, as requested.

Notice of the filing was published in the *Federal Register* with comments, protests, or interventions due on or before February 15, 2017. Under 18 C.F.R. § 385.210, interventions are timely if made within the time prescribed by the Secretary. Under 18 C.F.R. § 385.214, the filing of a timely motion to intervene makes the movant a party to the proceeding, if no answer in opposition is filed within fifteen days. No protests or adverse comments were received.

This action does not constitute approval of any service, rate, charge, classification or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents; nor shall such action be deemed as recognition of any claimed contractual right or obligation affecting or relating to such service or rate; and such action

[1] This agreement is designated as Louisville Gas and Electric Company, Transmission Tariff, Part V_ATTACH Q, Part V_ATTACH Q Agts btw TO and ITO and RC, 12.0.0.

is without prejudice to any findings or orders which have been made or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the applicant(s).

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Penny S. Murrell, Director
Division of Electric Power
Regulation – Central

Document Content(s)

Rebuttal Exhibit LEB-5

Letter from PHMSA to NARUC

U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

Administrator

1200 New Jersey Avenue SE
Washington, DC 20590

DEC 19

Mr. Tony Clark
Chairman of the Board and President
National Association of Regulatory Utility Commissioners
1101 Vermont Avenue, NW
Suite 200
Washington, DC 20005

Ms. Collette Honorable
Chair, NARUC Pipeline Safety Task Force
National Association of Regulatory Utility Commissioners
1101 Vermont Avenue, NW
Suite 200
Washington, DC 20005

Dear Mr. Clark and Ms. Honorable:

As U.S. Department of Transportation (DOT) and the National Association of Regulatory Utility Commissioners (NARUC) continue to support efforts to accelerate the repair, rehabilitation, and replacement of high-risk infrastructure in pipeline systems, we appreciate the NARUC's continued diligence in promoting rate mechanisms that will encourage and will enable pipeline operators to take reasonable measures to repair, rehabilitate or replace high-risk gas pipeline infrastructure. We have prepared, and attached, a white paper on state pipeline infrastructure replacement programs in the hope that you will share it with your members as a resource for encouraging more States to adopt alternative or more flexible rate mechanisms that will facilitate the replacement or repair of high-risk pipelines.

As you know, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has regulatory authority in regard to the safety of our nation's pipelines. PHMSA, however, does not have the authority to determine the routing, rates, or other terms and conditions of service for gas pipelines. The Federal Energy Regulatory Commission makes these determinations for interstate gas pipelines, and the State public utility commissions you represent typically do the same for intrastate gas pipelines. Most State commissions are also responsible for oversight of intrastate pipeline safety through certifications or agreements with PHMSA.

Many State public utility commissions have encouraged the timely repair, rehabilitation, and replacement of high-risk gas pipeline infrastructure through special rate mechanisms. Some legislatures have also provided their State public utility commissions with specific statutory authority to approve such programs for intrastate gas lines. A comprehensive list of these programs is available at http://opsweb.phmsa.dot.gov/pipelineforum/pipeline-systems/state-pipeline-system/state-replacement-programs/.

We believe that the timely repair, rehabilitation, and replacement of high-risk gas pipeline infrastructure are critical to ensuring public safety. A series of recent gas pipeline accidents, including the September 9, 2010 San Bruno, California accident, the January 19, 2011 Philadelphia, Pennsylvania accident, and the February 10, 2011 accident, show the terrible loss of life and property that can occur without adequate attention to the integrity of pipeline infrastructure.

PHMSA believes that an effective program for ensuring the timely rehabilitation, repair, or replacement of high-risk gas pipelines might have helped prevent these accidents. Accordingly, we recommend that State public utility commissions consider accelerating work on the following kinds of high-risk intrastate gas infrastructure in the future:

- Cast iron gas mains, which can be prone to failure as a result of graphitization or brittleness;
- Plastic pipe manufactured in the 1960s to the early 1980s, which is susceptible to premature failures as a result of brittle-like cracking;
- Mechanical couplings used for joining and pressure sealing pipe, which are prone to failure under certain conditions;
- Bare steel pipe without adequate corrosion control (i.e., cathodic protection or coating);
- Copper piping;
- Older pipe, if it is vulnerable to failure from time-dependent forces, such as corrosion, stress corrosion cracking, settlement, or cyclic fatigue factor; and
- Pipelines with inadequate construction records or assessment results to verify their integrity.

PHMSA requests your support in ensuring that State commissions implement effective programs for the timely repair, replacement, and rehabilitation of high-risk gas pipeline infrastructure.

I look forward to continuing to work with the NARUC on pipeline safety and welcome any thoughts that you have on the issues discussed in this letter. Please send your response to Jeffrey Wiese, Associate Administrator for Pipeline Safety, or to contact me if you have any questions or concerns.

Regards,

Cynthia L. Quarterman

Enclosure: White Paper

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE	**)**	
GAS AND ELECTRIC COMPANY	**)**	**CASE NO. 2016-00371**
FOR AN ADJUSTMENT OF ITS	**)**	
ELECTRIC AND GAS RATES	**)**	
AND FOR CERTIFICATES OF	**)**	
PUBLIC CONVENIENCE AND	**)**	
AND NECESSITY	**)**	

REBUTTAL TESTIMONY OF
DANIEL K. ARBOUGH
TREASURER
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: April 10, 2017

Q. Please state your name, position and business address.

A. My name is Daniel K. Arbough. I am the Treasurer for Louisville Gas and Electric Company ("LG&E" or the "Company") and an employee of LG&E and KU Services Company, which provides services to LG&E and Kentucky Utilities Company ("KU") (collectively, the "Companies"). My business address is 220 West Main Street, Louisville, Kentucky.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut certain arguments made in the direct testimony of intervenors in this case. Specifically, I will explain (1) that Attorney General ("AG") and Louisville Metro witness Dr. Woolridge's adjustment to LG&E's capital structure is unreasonable; (2) that Department of Defense and all other Federal Executive Agencies ("DOD") witness Mr. Walters' position on LG&E's equity ratio is incorrect; (3) that Dr. Woolridge's adjustment to the cost of debt, if accepted, should apply to all debt components; (4) that AG witness Mr. Smith's proposed disallowance of PPL Service Corporation ("PPL Services") charges is unreasonable and unwarranted; and (5) that the adjustments proposed by Kentucky Industrial Utilities Customers, Inc. ("KIUC") witness Mr. Kollen, Kroger witness Mr. Townsend, and Louisville Metro witness Mr. Pollock to defer the collection of prudent costs could impair the Company's credit metrics.

Capital Structure

Q. Please summarize Dr. Woolridge's adjustment to LG&E's capital structure.

A. Dr. Woolridge recommends imposing an artificial capital structure of 50.0% debt and 50.0% equity to set the Company's rates, which differs from the capital structure proposed in my direct testimony of 3.82% short-term debt, 42.91% long-term debt and 53.27% common equity. Dr. Woolridge claims this adjustment is necessary to make LG&E's capital structure "more reflective of the capital structures of electric utility and gas distribution companies as well as LG&E's ultimate parent company, PPL Corporation ("PPL")."[1]

Q. Did Mr. Walters make a similar claim on behalf of the DOD?

A. Yes, he did. Although not proposing an adjustment to LG&E's capital structure, Mr. Walters claims the Company's capital structure contains an unreasonably high balance of common equity to total capital than necessary to balance its financial risk.[2]

Q. Are Dr. Woolridge and Mr. Walters correct that LG&E's capital structure is not comparable to other electric utility and gas distribution companies, or is unreasonably high?

A. No, they are not correct. In Adrien McKenzie's direct testimony on behalf of LG&E, he demonstrated that 22 of the 50 operating companies in his peer group, or nearly half, had equity ratios at year-end 2015 that were equal to or greater than the 53.27% common equity requested by the Company.[3] These peer utilities are the group of electric and gas utility operating companies owned by the firms in the proxy group Mr. McKenzie used to estimate the cost of equity.[4]

In fact, of the utilities in Dr. Woolridge's proxy group that are not in Mr. McKenzie's, 13 of the 42 have equity ratios greater than the Company's requested percentage in this case.

[1] Direct Testimony of J. Randall Woolridge, Ph.D. on Behalf of the Kentucky Office of the Attorney General of March 3, 2017 (Case No. 2016-00371) at Summary of Direct Testimony.
[2] Direct Testimony of Christopher C. Walters on behalf of United States Department of Defense and all other Federal Executive Agencies of March 3, 2017 (Case No. 2016-00371) at 3.
[3] Direct Testimony of Adrien M. McKenzie on behalf of Louisville Gas and Electric Company of Nov. 23, 2016 (Case No. 2016-00371) at 25.
[4] *Id.*

Q. Is the Company's equity ratio in this case consistent with LG&E's equity ratios over the last few years?

A. Yes, the equity percentage in this case is very consistent with the Company's capital structure over the last decade. Since 2007, LG&E's quarter-end equity ratios have stayed within 51.9% to 56.5%. The 53.27% in this case falls squarely in the middle of this range. These ratios have been reviewed in every rate case during this time period without an adjustment, or even criticism, by the Commission. In fact, in 2009-00549, Dr. Woolridge proposed the exact same adjustment. In that case, LG&E's capital structure contained 53.86% equity, which is slightly higher than in this case. The Commission rejected Dr. Woolridge's adjustment because the equity ratio helped "provide LG&E greater access to capital markets, access to lower-cost debt and greater financial flexibility."[5] As I explained in my direct testimony, these equity ratios have allowed LG&E to have among the lowest debt costs of its peer utilities.[6] Arbitrarily reducing the equity ratio that contributed to LG&E's ability to obtain low debt costs is unreasonable.

Q. Why does the Company keep its equity ratio within this range?

A. As I explained in my direct testimony,[7] LG&E continues to aim for an "A" rating from Moody's and Standard & Poor's. To do so, the Company must maintain a sufficient percentage of equity to fall within the rating agencies' guidelines.

Indeed, Moody's A3 rating of LG&E is based in significant part on its equity ratio. In its October 2016 credit opinion Moody's stated "We expect LG&E's

[5] *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Electric and Gas Base Rates* (Case No. 2009-00549 (Ky. PSC July 30, 2010) at 26-27.
[6] See page 12 of my Direct Testimony filed Nov. 23, 2016.
[7] See pages 8-10 of my direct testimony.

financial metrics to remain supportive of its rating levels based on the targeted capital structure of 52% equity, which is calculated net of goodwill and Moody's standard adjustments."[8] This is objective evidence that the Company's equity ratio is premised on obtaining credit ratings that allow LG&E to obtain favorable debt costs, and further proves that Dr. Woolridge's proposed reduction could negatively impact the Company's risk profile.

Q. Dr. Woolridge also notes that LG&E's ultimate parent, PPL, has a higher level of debt than the Companies. Is this relevant?

A. No. PPL is a public utility holding company, not itself a regulated utility. PPL's financial statements are consolidated statements for all of its subsidiaries, including those in the United Kingdom. These subsidiaries include a variety of companies with a range of risk profiles. This Commission has long recognized the importance of LG&E maintaining its ability to access the capital markets and raise funds independent of its parent. In Case No. 2010-00204, the Commission, in Appendix C to the September 30, 2010 Order approving PPL's acquisition of LG&E and KU, required the Companies to "each maintain its own corporate credit rating as well as ratings for long-term debt from Moody's and S&P or their successor rating agencies."

Q. What is your recommendation regarding Dr. Woolridge's proposed adjustment to LG&E's capital structure?

A. My recommendation is that the Commission reject the adjustment and set rates for LG&E based on the capital structure proposed in my direct testimony.

[8] A copy of this report was provided in response to AG 1-266.

Cost of Debt

Q. Please summarize the adjustment Dr. Wooldrige has proposed to LG&E's cost of debt.

A. Dr. Woolridge has proposed an adjustment to reduce LG&E's long-term debt cost rate from 4.12% to 4.10% to reflect a recent interest rate swap termination.[9] The interest rate swap termination Dr. Woolridge is referring to is with Bank of America Merrill Lynch. On December 14, 2016, in Case No. 2016-00393, the Commission permitted LG&E to establish for accounting purposes a regulatory asset for the termination payment due to Bank of America Merrill Lynch as a result of the Company terminating the swap. When LG&E filed its application in Case No. 2016-00393, it expected the termination payment to be approximately $13 million. Due to interest rate increases that occurred in the market between the date of the preparation of the application and the date of the termination of the interest rate swap, the actual termination payment was $9.409 million.

Q. Does Dr. Woolridge's adjustment fairly capture the rise in interest rates that has occurred?

A. No, because it is incomplete. The $13 million estimated termination payment was based on interest rate information consistent with the interest rate information used to calculate all of LG&E's debt costs, which are among the very lowest of its peers. Notably, no intervenor claimed that the Company's debt costs were unreasonable or too high. If the Commission chooses to accept Dr. Woolridge's adjustment, which is based on the increase in interest rates the market is experiencing, it should likewise

[9] Woolridge Direct at 33.

reflect higher interest rates across all of LG&E's variable rate debt costs, and projected debt issuance costs. Otherwise, Dr. Woolridge will be permitted to select the one instance in which the rising interest rates reduce a debt cost, while ignoring all of the other affected costs that will increase. The Commission should reject Dr. Woolridge's selective ratemaking claim.

PPL Services Expense

Q. Please summarize the adjustment Mr. Smith has proposed regarding PPL Services expense.

A. Mr. Smith has proposed disallowing the costs charged from PPL Services to LG&E in the forecast test year.[10] Without an affirmative showing, he erroneously asserts that the charges being allocated to LG&E are duplicative of work being performed by the LG&E and KU Service Company. He also mistakenly contends that PPL Services "is another affiliated service company that was established to provide shared services to the PPL operations in Pennsylvania."[11] Neither statement is accurate.

Q. Please describe PPL Services and the type of work it performs for which LG&E is charged.

A. Contrary to Mr. Smith's contention, PPL Services was not established to support operations in Pennsylvania. As explained in response to AG 1-51, PPL Services supports all of PPL's operations organization-wide, not only domestically but in the United Kingdom, as well, by acting as a billing agent and providing administrative, technical, management, and other services to its affiliates. Because PPL Services

[10] Direct Testimony of Ralph C. Smith on behalf of the Kentucky Office of the Attorney General of March 3, 2017 Public Redacted Version (Case No. 2016-00371) at 50-53.
[11] *Id.* at 53.

supports a wide array of assets and operations, it is able to leverage its buying power to achieve economies of scale in several fundamental operational areas, such as placing property insurance, providing pension fund investment management oversight, paying fees for mandatory Sarbanes Oxley compliance activities such as the Public Company Accounting Oversight Board ("PCAOB"), and buying IT software. Instead of having employees perform these functions within each subsidiary, these activities are centralized and the costs are directly attributed to the affiliates receiving the benefit of the centralized function. In the case of LG&E and KU, costs are directly attributed to the utilities' immediate parent, LG&E and KU Energy LLC, through LG&E and KU Services Company. LG&E and KU Services Company then allocates the costs to the companies receiving the benefit, including the utilities, based upon the appropriate ratio. All of these transactions, including calculation of the appropriate ratio, are determined in accordance with the Cost Allocation Manual on file with the Commission and in compliance with the laws regarding affiliate transactions. Morever, the transactions are also in accordance with LG&E's and KU's commitments in Case No. 2010-00204, as the Commission's order approving the merger with PPL stated that "[c]osts of PPL or its service company will not be allocated to LG&E and KU except for those ***costs directly incurred in the provision of goods or services*** to the utilities and that are directly assigned for that purpose."[12]

[12] *In the Matter of: Joint Application of PPL Corporation, E.ON AG, E.ON US Investments Corp., E.ON U.S. LLC, Louisville Gas and Electric Company, and Kentucky Utilities Company for Approval of an Acquisition of Ownership and Control of Utilities* (Case No. 2010-00204) (Ky. PSC Sept. 30, 2010) at 8.

Q. Is the work performed by PPL Services duplicative of the work performed by LG&E and KU Services Company?

A. No, it is not or it would not be accepted by LG&E. Moreover, Mr. Smith's testimony does not identify a single charge or item of work that he alleges was performed by both PPL Services and LG&E and KU Services Company. Instead, he assumes without providing any support that because certain categories of charges from the two service companies are booked to the same FERC accounts, the work must be duplicative.

Q. Does LG&E and KU Services Company provide services for PPL Services?

A. Like PPL Services, LG&E and KU Services Company performs centralized functions and attributes the related costs to the affiliates receiving the benefit of the centralized function. To the extent PPL Services benefits from these functions, LG&E and KU Services Company charges PPL Services for its share of the costs.

Q. Do you have a recommendation regarding Mr. Smith's adjustment?

A. My recommendation is that the Commission reject Mr. Smith's adjustment. To disallow PPL Services costs, which includes essential expenses such as procuring insurance and paying fees for mandatory Sarbanes Oxley compliance activities, is to punish LG&E for utilizing an affiliate company to take advantage of economies of scale.

Deferring the Collection of Prudent Costs

Q. Several witnesses have proposed adjustments that would have the effect of deferring the Company's collection of prudent costs. Can you briefly describe those?

A. Yes. KIUC witness Mr. Kollen proposes to defer the recovery of the net salvage costs for generation plants and to use a longer life span for certain generation plants. In addition, Mr. Kollen and Kroger witness Mr. Townsend propose a normalization adjustment for generation outage expense. Louisville Metro witness Mr. Pollock recommends amortizing so-called "surplus" depreciation reserve, which is a characterization I do not agree with.

Q. Do you agree with these adjustments?

A. No. Each of these adjustments has the effect of deferring the collection of prudent costs incurred by the Company. The intervenors may argue that making these adjustments will not impact the income of the Company, and, therefore, the Company should be willing to accept these adjustments. However, cash is required to fund the costs, and deferring the recovery of such costs will result in an impairment of the credit metrics. As noted by Moody's in its rating methodology for utilities (see page 15 of exhibit DKA-3 in my direct testimony), "The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are ***crucial*** credit considerations." (emphasis added). A decision to prevent the Company from recovering its costs in a timely fashion could impact the market consensus that Kentucky provides a constructive regulatory environment. Such an outcome, combined with declining credit metrics, could result in higher interest rates on future debt issuances.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Daniel K. Arbough

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of April 2017.

Judy Schooler (SEAL)

Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**)))**	**CASE NO. 2016-00370**
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**))))**	**CASE NO. 2016-00371**

REBUTTAL TESTIMONY

OF

ADRIEN M. MCKENZIE, CFA

on behalf of

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: April 10, 2017

REBUTTAL TESTIMONY

OF

ADRIEN M. MCKENZIE

TABLE OF CONTENTS

Exhibit No.	**Description**
12	Allowed ROEs (RRA Averages)
13	Allowed ROEs (Utility Group)
14	Earned ROEs (Utility Group)
15	Capital Structure (Electric Operating Companies)
16	Revised Walters Risk Premium

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. Adrien M. McKenzie, 3907 Red River, Austin, Texas, 78751.

Q2. ARE YOU THE SAME ADRIEN M. MCKENZIE THAT PREVIOUSLY SUBMITTED PREFILED DIRECT TESTIMONY IN THIS CASE?

A2. Yes, I am.

Q3. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A3. My testimony to the Kentucky Public Service Commission ("KPSC" or the "Commission") addresses the testimony of Dr. J. Randall Woolridge, submitted on behalf of the Kentucky Office of Attorney General ("OAG") and the Louisville/Jefferson County Metro Government ("Louisville Metro"), Mr. Richard Baudino, on behalf of the Kentucky Industrial Utility Consumers ("KIUC"), Mr. Christopher C. Walters on behalf of the United States Department of Defense and all other Federal Executive Agencies ("DOD"), and Mr. Gregory W. Tillman, on behalf of Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"),[1] concerning the fair rate of return on equity ("ROE") that Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies") should be authorized to earn on their investment in providing electric and gas utility service. In addition, I respond to the capital structure recommendations of Dr. Woolridge.

Q4. HAVE YOU PREPARED WORKPAPERS SUPPORTING YOUR REBUTTAL TESTIMONY?

A4. Yes. Workpapers including supporting documents referenced in my rebuttal testimony and related exhibits are attached as Appendix A.

[1] I refer, collectively, to Dr. Woolridge, Mr. Baudino, and Mr. Walters as the "ROE Witnesses" since they made specific ROE recommendations. Mr. Tillman testified generally about the ROE issue without making a specific proposal.

A. Summary of Conclusions

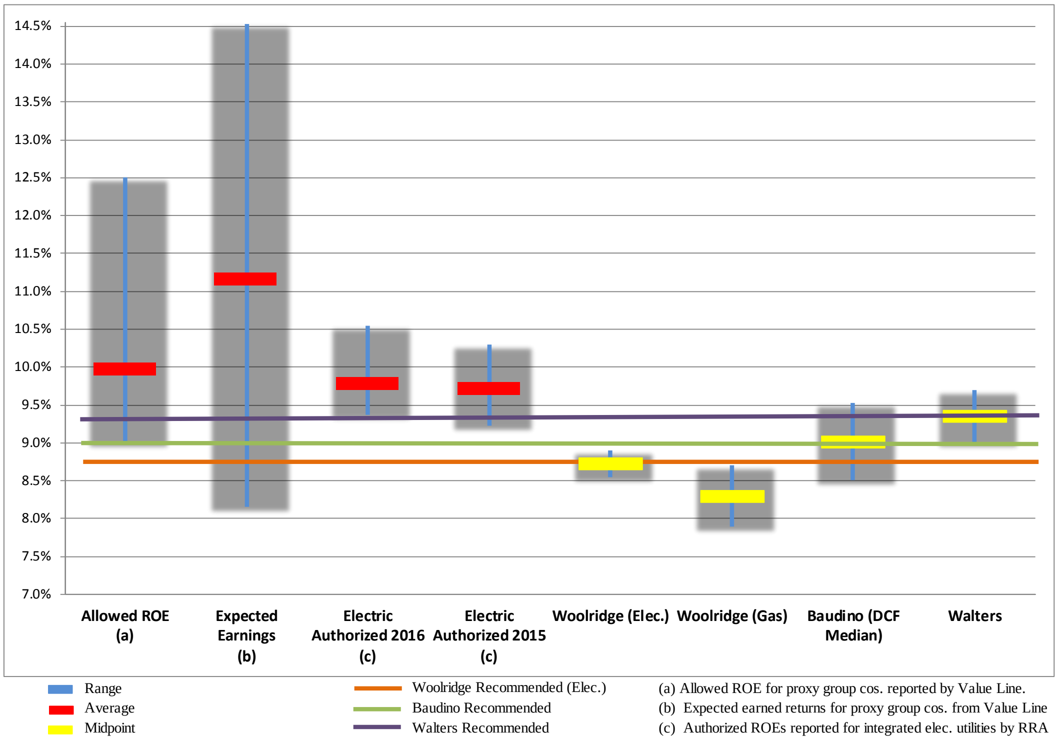
Q5. PLEASE SUMMARIZE THE RECOMMENDATIONS OF THE ROE WITNESSES.

A5. Dr. Woolridge recommends an ROE of 8.75% for KU and the electric operations of LG&E, while his recommendation for LG&E's gas operations is 8.70%. Mr. Baudino proposes an ROE of 9.00% for the Companies, while Mr. Walters' recommends an ROE of 9.35% for LGE.

Q6. PLEASE SUMMARIZE YOUR RESPONSE TO THE ROE WITNESSES' TESTIMONY.

A6. Their cost of equity recommendations are simply too low and fail to reflect the risk perceptions and return requirements of real-world investors in the capital markets. The significant shortfall between their recommendations and the ROE benchmarks discussed in my rebuttal testimony are illustrated in the figure below.

FIGURE R-1
COMPARISON OF ROE RECOMMENDATIONS TO BENCHMARKS



Q7. WHAT ARE YOUR PRINCIPAL CONCLUSIONS REGARDING THE RECOMMENDATIONS OF DR. WOOLRIDGE?

A7. I demonstrate that Dr. Woolridge's recommendations should be ignored in their entirety based on the following findings:

- Dr. Woolridge's recommended ROEs of 8.70%-8.75% are extreme outliers and should be rejected on their face.
- Dr. Woolridge's discussion of current capital market conditions is potentially misleading.
- Dr. Woolridge's focus on market-to-book ratios ("M/B") is misguided and not relevant to the determination of reasonable ROEs in this case.
- The proxy group selected by Dr. Woolridge incorrectly excludes several utilities that should have been considered in his analyses.
- His Discounted Cash Flow ("DCF") analysis contains several flaws, including his reliance on dividend per share and historical data for estimating the DCF growth term, his

inclusion of illogical results stemming from unrealistically low growth rates (including numerous negative growth rates), and his reference to growth in gross domestic product ("GDP") as an upper bound on utility company growth rates. As a result, his conclusions are unreliable and should be ignored.

- Dr. Woolridge's application of the DCF model based on the internal, "br" growth rate is flawed and incomplete,
- The Capital Asset Pricing Model ("CAPM") results reported by Dr. Woolridge were based on a hodge-podge of historical data that failed to reflect forward-looking expectations, particularly in light of current conditions in the capital markets.

Furthermore, Dr. Woolridge failed to consider the Empirical CAPM ("ECAPM") and risk premium approaches which are legitimate ROE methods. His rejection of flotation costs is at odds with the conclusions of recognized financial research and his own admission that these are legitimate expenses that should be recovered. Finally, his criticisms of my size adjustment, market return calculation, expected earnings approach, and non-utility DCF analysis are without merit. Taken as a whole, these shortcomings ensure that Dr. Woolridge's recommended ROEs fall well below fair and reasonable levels for the Companies' utility operations. In fact, his recommendations are so far below a reasonable ROE range that they should be rejected on their face. With respect to Dr. Woolridge's recommended capital structure, my rebuttal testimony demonstrates that there is no basis for the hypothetical ratios he proposes.

Q8. WHAT ARE YOUR PRINCIPAL CONCLUSIONS REGARDING THE RECOMMENDATIONS OF MR. BAUDINO?

A8. Mr. Baudino's 9.0% ROE recommendation is also below realistic investor expectations. My rebuttal testimony demonstrates that:

- Mr. Baudino mistakenly excludes legitimate companies from his proxy group, casting doubt on his ROE conclusions.
- Mr. Baudino places too much emphasis on dividend growth and failed to evaluate the reasonableness of individual DCF

estimates. As a result, his conclusions are unreliable and should be ignored.

- Mr. Baudino's application of the DCF model based on the internal, "br" growth rate is flawed and incomplete.
- Mr. Baudino's application of the CAPM was compromised by reliance on historical data, while his forward-looking approach was marred by methodological shortcomings and inconsistencies.
- Like Dr. Woolridge, Mr. Baudino's rejection of a flotation cost adjustment contradicts the findings of the financial literature and the economic requirements underlying a fair rate of return on equity.

Finally, my rebuttal testimony demonstrates that Mr. Baudino's criticisms of my alternative applications and conclusions are misguided and should be ignored.

Q9. WHAT ARE YOUR PRINCIPAL CONCLUSIONS REGARDING THE RECOMMENDATIONS OF MR. WALTERS?

A9. Mr. Walters recommends an ROE of 9.35% for LGE. I demonstrate that Mr. Walters' recommendation is biased downward and lacks credibility based on the following:

- Mr. Walters' DCF approach is weakened because he includes low-end outliers in his final results.
- He ignores a readily available and widely followed source of analysts' growth rates in his DCF methodology.
- He relies on a multi-stage growth DCF model that wrongly assumes growth in GDP is an upper limit on utility growth.
- The CAPM results reported by Mr. Walters are suspect because they are based on historical data, they fail to correct for an observed bias in the CAPM result, and they ignore the impact of company size on expected returns.
- His risk premium analysis is flawed because he rejects the well-documented, inverse relationship between equity risk premiums and interest rate levels.

Mr. Walters' analyses also suffer from many of the same deficiencies identified above in connection with Dr. Woolridge's and Mr. Baudino's analyses. His criticisms of my Expected Earnings approach and Non-Utility DCF analysis are without merit and his criticism of my ROE risk adjustment is misguided. Taken as a whole, these flaws mean that Mr. Walters' recommended ROE also falls well below a fair and reasonable level for the Companies.

B. Comparison of ROE Recommendations to Accepted Benchmarks

Q10. CAN YOU ILLUSTRATE THE EXTREME NATURE OF THE ROE WITNESSES' RECOMMENDATIONS?

A10. Yes. If adopted, the 8.75% electric ROE suggested by Dr. Woolridge and the 9.0% value offered by Mr. Baudino would be the lowest ROEs granted to vertically-integrated electric utilities by a state commission in recent history.[2] These recommendations are also significantly below the 10.0% ROE specified in the Settlement Agreement approved by the Commission in June 2015,[3] as well as the 9.8% value authorized more recently in connection with the Companies' recovery of environmental costs.[4] In this light, the 9.35% recommendation of Mr. Walters must also be considered unrealistic. As the table below indicates, utility bond yields are comparable to those corresponding to the 10.0% ROE approved in 2015, and have increased on the order of 40 to 60 basis points since the 9.8% ROE was authorized in August 2016. These comparisons show that the recommendations of the ROE Witnesses defy common sense and further emphasize the extreme nature of their proposals.

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[2] Regulatory Research Associated reported that Maui Electric was granted an ROE of 9.0% on May 31, 2013. However, the base ROE determined by the Public Utilities Commission of Hawaii was 9.50%, to which a 50 basis point penalty was applied due to "apparent system inefficiencies which negatively impact MECO's customers." (Docket No. 2011-0092, Decision and Order No. 31288, p, 107). Beyond that, the lowest authorized ROE for a vertically-integrated electric utility was 9.25% authorized for Northern States Power-Minnesota in their South Dakota jurisdiction on June 19, 2012.

[3] *E.g.*, Case No. 2014-00371, *Application of Kentucky Utilities Company for an Adjustment of its Electric Rates* (Ky. PSC June 30, 2015).

[4] *E.g.*, Case No. 2016-00026, *Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of its 2016 Compliance Plan for Recovery by Environmental Surcharge*, (Ky. PSC August 8, 2018).

TABLE R-1
CHANGE IN BOND YIELDS

	Utility Bond Yields	
	A-rated	**Baa-rated**
Previous Rate Case		
6-Mo. Average Jan. - Jun. 2015 (a)	3.88%	4.65%
February 2017 Average	4.18%	4.58%
Change	**0.30%**	**-0.07%**
Environmental Surcharge Case		
August 2016 Average	3.59%	4.20%
February 2017 Average	4.18%	4.58%
Change	**0.59%**	**0.38%**

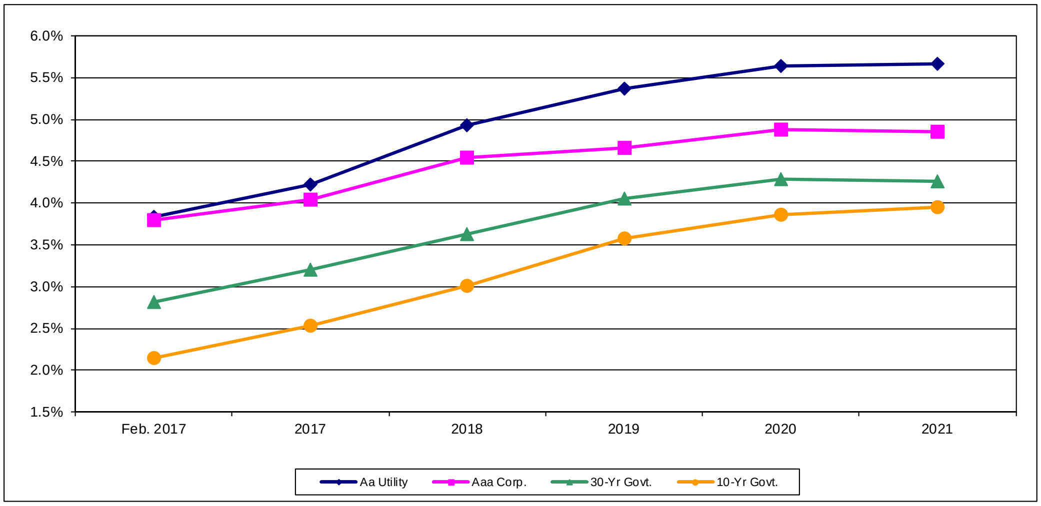
Source : Moodys Investors Service.

(a) Rates shown are six-month averages for the period January 2015 to June 2015, considered to be the period of record.

Q11. WHAT IS THE EXPECTED DIRECTION OF INTEREST RATES AND HOW DOES THIS IMPACT THE EVALUATION OF A FAIR ROE IN THIS PROCEEDING?

A11. Interest rates are expected to increase. Below is an update of Figure 3 (Interest Rate Trends) from my Direct Testimony:

FIGURE R-2
INTEREST RATE TRENDS



Source:
Value Line Investment Survey, Forecast for the U.S. Economy (Mar. 3, 2017)
IHS Global Insight (Jan. 3, 2017; Nov. 30, 2016)
Energy Information Administration, Annual Energy Outlook 2017 (Jan. 5, 2017)
Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 35, No. 12 (Dec. 1, 2016)

As the figure shows, investors continue to anticipate that interest rates will increase significantly from present levels. These projections are from forecasting services that are highly regarded and widely referenced, as I discuss in my Direct Testimony (at 15-16). The interest rate increases shown in the figure above are on the order of 150 basis points through 2021, which implies higher long-term capital costs over the period when rates established in this proceeding will be in effect.

Q12. DO THE ROE WITNESSES ACKNOWLEDGE THAT INTEREST RATES ARE EXPECTED TO INCREASE?

A12. Yes. In selecting the risk-free rate for use in his CAPM analysis, Dr. Woolridge states that "[g]iven the recent range of yields <u>and the possibility of higher interest rates</u>, I use 4.0% as the risk-free rate, or R_f, in my CAPM."[5] Given that the current 30-year U.S. Treasury bond rate (the rate Dr. Woolridge uses as the risk-free rate

[5] Woolridge LGE Direct at 60 (emphasis added).

in his CAPM analysis) is around 3.1%, Dr. Woolridge clearly recognizes that investors anticipate a substantial increase in future interest rates.

Similarly, Mr. Walters also acknowledges that rising interest rates imply a higher cost of equity. He places more weight on his high-end risk premium estimates "because of the relatively low level of interest rates now but relative upward movements of utility yields more recently."[6] Mr. Walters' Treasury bond risk premium and CAPM analyses also rely on projected interest rates. Within these analyses, he projects Treasury bond yields to increase from the current level of approximately 3.10% to 3.70%.[7]

Q13. WHAT DO THESE EXPECTATIONS IMPLY WITH RESPECT TO THE ROES FOR THE COMPANIES MORE GENERALLY?

A13. Largely because of unprecedented Federal Reserve policies, current capital costs are not representative of what is likely to prevail over the near-term future. As indicated in my Direct Testimony,[8] regulators have recognized the shortcomings of the DCF approach. In a more recent opinion, FERC reiterated its position that current capital market conditions may undermine the reliability of the DCF model, and for this reason, ROE model results should be evaluated with even more critical judgment and focus:

> As described above, evidence in the record regarding historically low interest rates and Treasury bond yields as well as the Federal Reserve's large and persistent intervention in markets for debt securities are sufficient to find that current capital market conditions are anomalous.[9]
>
> Similarly, while Complainants provide evidence that interest rates have been trending downwards, the current levels may be so low as to cause irregularities in the outputs of the DCF. Despite such

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[6] Walters Direct at 53.
[7] Walters Direct at 55.
[8] McKenzie LGE Direct at 6-7, 19.
[9] Opinion No. 551, 156 FERC ¶ 61,234 at P 124 (2016).

> yields remaining low for several years, we find that they are anomalous and could distort the results of the DCF model.[10]

Current capital market conditions make the process of setting a fair ROE even more demanding. In this environment, it is imperative that ROE model results be thoroughly tested against accepted benchmarks and compared to other checks of reasonableness.

Q14. IS IT NECESSARY THAT INTEREST RATE FORECASTS, LIKE THOSE MENTIONED ABOVE, BE PERFECTLY ACCURATE IN ORDER TO BE RELIED UPON?

A14. Absolutely not. I dealt with this topic in my Direct Testimony (at 34) in discussing the validity of analysts' growth forecasts, and the same principle applies here. In estimating investors' required rate of return, what investors expect, not what actually happens, is what matters most. While the projections of various services may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing expected interest rates and how they might influence the Companies' allowed ROE. Any difference in actual rates as compared to analysts' forecasts is beside the point. What is most important is that investors share analysts' views when the forecasts were made and incorporate those views into their decision making process, not the actual rates that ultimately transpire.

Q15. HOW DO THE ROE WITNESSES' RECOMMENDATIONS COMPARE TO RECENTLY-ALLOWED RETURNS FROM OTHER STATE COMMISSIONS?

A15. Allowed ROEs by other state commissions provide a general gauge of reasonableness for the outcome of a cost of equity analysis. In considering utilities with comparable risks, investors will always prefer to provide capital to the opportunity with the highest expected return. If a utility is unable to offer a return

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[10] *Id.*

similar to that available from other investment opportunities posing equivalent risks, investors will become unwilling to supply the utility with capital on reasonable terms. While the ROEs approved in other jurisdictions do not constrain the Commission's decision-making in this proceeding, it is important to understand that there would be a disincentive for investors to provide equity capital to the Companies if the Commission were to apply an unreasonably low ROE, compared to entities of comparable risk.

The recommendations of the ROE Witnesses are significantly below equity returns that have been allowed by other state regulatory commissions around the country. As shown on Exhibit No. 12, over the past 24 months the average allowed ROE (excluding adders and penalties) reported by Regulatory Research Associates for vertically-integrated electric utilities is 9.76%,[11] with the midpoint of the high and low values being 9.89%. Similarly, authorized ROE data reported to investors by The Value Line Investment Survey ("Value Line") for the specific firms in my proxy group also disprove the recommendations of the ROE Witnesses.[12] As shown in Exhibit No. 13, these ROEs average 10.0%, with the midpoint of the lowest and highest values being 10.75%. In other words, allowed returns for the utilities that the ROE Witnesses generally consider to be substitutes for the Companies indicate that their recommendations are too low to meet regulatory standards.

Q16. MR. TILLMAN EXCLUSIVELY REFERENCES ROES AWARDED IN RECENT RATE CASES.[13] WOULD IT BE APPROPRIATE TO USE RECENT ALLOWED RETURNS TO ESTABLISH THE COMPANIES' ROE DIRECTLY?

[11] For 2015, the average is 9.72%; for 2016, the average is 9.79%.
[12] Dr. Woolridge relies on my proxy group as one of his two electric groups; Mr. Baudino starts with my group before removing three companies due to data concerns; and Mr. Walters uses my group entirely.
[13] Tillman LGE Direct at 13-15.

A16. No, it would not. While data on allowed returns can have a role in evaluating a fair ROE, there is no basis to place undue weight on a single, summary statistic in lieu of comprehensive analyses and a case-specific evidentiary record. Most importantly, such an approach fails to satisfy the standards mandated by the U.S. Supreme Court in its *Bluefield* and *Hope* decisions, which dictate that the ROE reflect contemporaneous returns to investments of comparable risk.

These bedrock opinions require regulators to consider the individual and specific risks and financial circumstances facing the utility, as well as the capital market conditions and investor expectations concurrent with their deliberations. Meeting these standards necessitates detailed analyses and the application of financial models and approaches with inputs that are specific to the utility in question. In context of a rate case, alternative analyses and expert opinions are subject to thorough discovery and cross examination from all stakeholders, with the results being carefully weighed by regulators to arrive at their best estimate of the cost of equity.[14] Developing the evidentiary record necessary to satisfy the *Hope* and *Bluefield* tests is a rigorous process that cannot be reduced to an isolated summary statistic from an industry publication such as Regulatory Research Associates ("RRA").

Q17. PLEASE ELABORATE ON WHY A RECENT AVERAGE ROE REPORTED BY RRA FALLS SHORT OF ACCEPTED REGULATORY STANDARDS.

A17. Setting a utility's ROE is a very company-specific process, and is a function of investors' perceptions of the risks and prospects for the subject company at a given point in time. Meanwhile, quarterly allowed ROEs reported by RRA are not

[14] As the KPSC recognized, for the limited purposes of the Companies' environmental cost recovery, its reference to RRA data was largely driven by the fact that "no cost-of-equity models were presented by any party." Case No. 2016-00026, *Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of its 2016 Compliance Plan for Recovery by Environmental Surcharge*, (Ky. PSC August 8, 2018) at 29. That is not the case in this proceeding.

necessarily representative or directly comparable to the utility at hand. That is, there may be an "apples and oranges" issue when the RRA data is applied in the current rate setting environment.

For instance, there may a limited number of proceedings reported in any given quarter, which undermines the ability to make broader inferences as to the ROE for a specific utility. There can also be significant differences in investment risks (*e.g.*, credit ratings) between the utilities that are the subject of a specific quarterly average ROE reported by RRA and the subject company in a rate proceeding. There may be distinctions in financial policies that give rise to risk differences, functional differences (integrated utilities versus "wires only" distribution services), differentiation based on approved rate mechanisms (*e.g.*, decoupling and recovery riders and trackers) and regulatory conventions (*e.g.*, formula rate plans, forward test years), as well as other utility-specific characteristics (*e.g.* size differences, capital requirements, and economic conditions in the service territory). In some instances, ROEs reported by RRA may include disallowances or incentive adders based on management, customer service, safety, or reliability measures. Average authorized ROEs reported by RRA also include the results of settled cases, which may reflect a trade-off between other elements in a proceeding. On balance and over long periods, such as the forty-plus years covered by my risk premium study, there is no basis to suggest that ROEs resulting from settlements are biased one way or the other, but focusing on a narrow pool of recent cases may undermine this assurance.

For example, a review of the allowed returns for gas utilities reported by RRA for the fourth quarter of 2016 indicates that the 9.6% average allowed ROE was significantly impacted by two 9.00% observations pertaining to settlements for related utilities in New York. These proceedings involve multi-year rate plans that include earnings sharing provisions that would allow shareholders to benefit from excess earnings. As the New York Public Service Commission reported in its order:

> The Companies note that, although the Commission's methodology for establishing ROE results in returns that are among the lowest in the country for gas and electric utilities, they are willing to accept this result in light of the overall settlement reached by the parties.[15]

Gas utilities in New York also operate under revenue decoupling mechanisms that better match revenues with the underlying cost of service on an ongoing basis. These circumstances are not comparable to those faced by the Companies in this proceeding. Excluding these two related observations results in an average ROE in the fourth quarter of 2016 of 9.8% for gas utilities.

Finally, capital market conditions during the evidentiary record that underlies the decisions reported by RRA are not likely to be identical to those prevailing during a subsequent rate proceeding. The very nature of RRA's quarterly publication schedule ensures that there will always be a lag between the results it reports and the ongoing case under study. Capital markets are constantly in flux and the distinctions between the historical time periods underlying the past findings of other regulatory agencies undermine the use of recent RRA data as a primary means to establish a fair ROE in this case. All of these differences can lead to a potential disconnect between the broad summary statistics reported by RRA and the comprehensive and detailed analyses required to meet the *Hope* and *Bluefield* standards.

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[15] State of New York Public Service Commission, Case 16-G-0058 et al. (Dec. 16, 2016) at 27. In 2015 and 2016, there were six cases decided by the New York Public Service Commission, all with ROEs of 9.0%. In all of these cases, the New York PSC merely approved comprehensive settlements reached by all the parties, and the authorized ROE was a component of the overall agreement. Orange and Rockland Utilities concluded that the provisions of the stipulation relating to ROE "were very difficult to accept and were only acceptable in light of all the other provisions of the agreement." (New York Public Service Commission, *Order Adopting Terms of Joint Proposal and Establishing Electric Rate Plan*, Case 14-G-0494, October 16, 2015, page 12).

Q18. DON'T THESE SAME CONCERNS EQUALLY AFFECT YOUR USE OF THE RRA-REPORTED AUTHORIZED ROES TO CALCULATE YOUR RISK PREMIUM COST OF EQUITY ESTIMATE?

A18. No. My risk premium study considers all reported data concerning allowed ROEs over a forty-two year horizon. As a result, it incorporates findings that reflect regulators' broad assessment of the required rate of return for the electric utility industry in general, and is not unduly influenced by the specific risks or circumstances of a small subset of the industry that make up an isolated statistic based on decision in a particular calendar quarter. In addition, my application of the risk premium approach based on allowed ROEs from RRA specifically accounts for the impact of changes in capital market conditions by adjusting for the observed inverse relationship between equity risk premiums and interest rates, and by incorporating current bond yields when calculating the implied cost of equity.

Q19. COULD USE OF THE RECENT AVERAGE ROE FROM RRA AS THE AUTHORIZED ROE ALSO TIE THE HANDS OF THE COMMISSION?

A19. Yes. Placing undue weight on RRA data means, in effect, that the methods and deliberations used by other state regulators to determine the ROE would dictate the actions of the Commission. If a recent average ROE statistic from RRA is given substantial weight in establishing the authorized ROE, all of the methodologies, approaches, and assessments that are weighed and embedded in those results are also implicitly approved. In contrast to careful deliberation of a detailed and comprehensive evidentiary record on a case-by-case basis, the Commission would in large part relinquish control over the regulatory process and outcome in such a scenario.

Q20. CAN THE PROCESS BECOME CIRCULAR IF STATE REGULATORS WERE TO ROUTINELY ACCEPT ROE RESULTS FROM OTHER STATES AS THE BASIS TO SET A UTILITY'S RETURN?

A20. Yes. As noted above, the standard practice in regulatory proceedings is to consider the results of numerous approaches that are grounded in current capital market evidence when establishing a utility's ROE. If, instead, regulators were to simply rely on the most recent determinations of other state agencies, the connection between regulatory findings and investors in the capital markets would soon be broken.[16] The cost of equity is determined by investors, not by regulators, and such a circular outcome would undermine the standards governing the evaluation of a fair ROE. The New Hampshire Public Utilities Commission cited the pitfalls of such a process:

> The Company urged the PUC to consider, in making its determination of the Company's allowed ROE, numerous ROEs set by other regulatory agencies in other jurisdictions. Such a "bald comparison" between the Company and these other companies is flawed. The ROEs set in other jurisdictions may combine with and reflect business, regulatory or financial risk differences of those other jurisdictions that do not apply to New Hampshire, or to utilities operating within New Hampshire. . . . There is also no evidence in the record as to whether ROE was litigated or the result of a settlement in the other jurisdictions. Presuming that it could consider an ROE from another jurisdiction without a circular effect, which is questionable, the PUC would need additional information. Therefore, without a complete picture of the companies cited by the Company and the cases in which the ROEs were decided, the rate of profit allowed these other utilities by regulatory agencies in other jurisdictions is simply not useful to PUC's determination of the Company's current cost of common equity.[17]

For these reasons, state regulatory agencies are charged with the responsibility of independently evaluating detailed evidence to establish an ROE corresponding to the specific risks, capital market conditions, and investor

[16] While RRA data may be one factor considered by investors in developing their expectations, the required return is a function of the underlying risks associated with the utility at issue and the other investment opportunities available in the capital markets, including non-utility firms.
[17] *EnergyNorth Natural Gas, Inc.*, Case No. DG 08-009 (N.H. PUC Feb. 20, 2009) (footnotes omitted).

expectations facing the utility under its jurisdiction. This is precisely the standard dictated by the *Hope* and *Bluefield* decisions.

Q21. ARE YOU SAYING THERE IS NO PLACE FOR RRA DATA IN THIS PROCESS?

A21. No. I use such data in my risk premium approach as an input to calculate annual average historical risk premiums, which are then adjusted to account for changes in interest rates and specific risk differences. The resulting cost of equity estimate is extremely useful because, at its core, it is based on current and expected capital market conditions and on the fundamental financial principle that, due to differences in risk, the cost of equity must exceed the cost of debt. Using this method, allowed ROE data from RRA is one of a number of inputs in a comprehensive, multi-year study that ultimately leads to a cost of equity estimate specific to the utility at hand and steeped in both investor expectations and financial theory.

As discussed earlier, it is also common to reference allowed ROEs reported by RRA as a benchmark or guidepost when assessing the reasonableness of cost of equity estimates derived from primary methodologies, such as the DCF and CAPM. In other words, RRA data is valuable as a "secondary" approach, useful in judging whether an ROE estimate based on the application of accepted financial models makes sense "on its face." In the right context, allowed ROE data from RRA can contribute in a valuable supporting role as part of the ROE estimation process.

Q22. WHAT OTHER BENCHMARKS INDICATE THAT THE ROE WITNESSES' RECOMMENDATIONS ARE TOO LOW TO BE CONSIDERED REASONABLE?

A22. Expected earned rates of return for other utilities provide yet another useful benchmark to gauge the reasonableness of the ROE Witnesses' recommendations. The expected earnings approach is predicated on the comparable earnings test, which developed as a direct result of the Supreme Court decisions in *Bluefield* and *Hope*, as I discuss in my Direct Testimony.[18] This test recognizes that investors compare the allowed ROE with returns available from other alternatives of comparable risk.

Importantly, the expected earnings approach explicitly recognizes that regulators do not set the returns that investors earn in the capital markets. Regulators can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q23. HAS THE EXPECTED EARNINGS APPROACH BEEN RECOGNIZED AS A VALID ROE BENCHMARK?

A23. Yes. This method predominated before the DCF model became fashionable with academic experts, and it continues to be used around the country.[19] A textbook prepared for the Society of Utility and Regulatory Analysts labels the comparable

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[18] McKenzie LGE Direct at 52-54. The *Bluefield* and *Hope* decisions refer to *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) and *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[19] For example, the Virginia State Corporation Commission is required by statute (Virginia Code § 56-585.1.A.2.a) to consider the earned returns on book value of electric utilities in its region. Similarly, FERC concluded that, "The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's market cost of equity." Opinion No. 531-B, 150 FERC ¶ 61,165 at P 128 (2015). Another example is the Idaho Public Utilities Commission, which also references return on book equity evidence. *See, e.g.*, Order No. 29505, Case No. IC-E-03-13 at 38 (Idaho Public Utilities Commission, May 25, 2004).

earnings approach the "granddaddy of cost of equity methods" and points out that the amount of subjective judgment required to implement this method is "minimal," particularly when compared to the DCF and CAPM methods.[20] The *Practitioner's Guide* notes that the comparable earnings test method is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases,[21] as well as sound regulatory economics. Similarly, *New Regulatory Finance* concluded that, "because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with Comparable Earnings, is highly meaningful."[22]

Q24. DID MR. BAUDINO RECOGNIZE THE ECONOMIC PREMISE UNDERLYING THE EXPECTED EARNINGS APPROACH?

A24. Yes. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. As Baudino recognized, economists refer to the returns that an investor must forgo by not being invested in the next best alternative as "opportunity costs."[23] Mr. Baudino went on to explain that, "investor's opportunity cost is measured by what she or he could have obtained in the next best alternative."[24]

Q25. WHAT ROES ARE IMPLIED BY THE EXPECTED EARNINGS APPROACH FOR THE UTILITY PROXY GROUP?

A25. The year-end returns on common equity projected by Value Line over its forecast horizon for the firms in the utility proxy groups referenced by the ROE Witnesses are shown on Exhibit No. 14. As shown there, once adjusted to mid-year, reference to the expected earnings approach implies an average cost of equity for the utilities referenced by Dr. Woolridge, Mr. Walters, and me of 11.2%, while the expected

[20] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," (2010) at 115-116.
[21] *Id.*
[22] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 395.
[23] Baudino Direct at 12.
[24] *Id.* at 13.

annual average cost of equity for Mr. Baudino's group is 11.0%. These book return estimates are an "apples to apples" comparison to the 8.75%-9.35% range of recommendations offered by of the ROE Witnesses.

Q26. PLEASE EXPLAIN THE RATIONALE FOR THE ADJUSTMENT TO CONVERT YEAR-END RETURNS TO AVERAGE RETURNS WHEN APPLYING THIS METHOD.

A26. The adjustment factor incorporated in my evaluation of expected returns is required because Value Line's reported returns are based on end-of-year book values. Since earnings is a flow over the year while book value is determined at a given point in time, the measurement of earnings and book value are distinct concepts. It is this fundamental difference between a flow (earnings) and point estimate (book value) that makes it necessary to adjust to mid-year in calculating the ROE. Given that book value will increase or decrease over the year, using year-end book value (as Value Line does) understates or overstates the average investment that corresponds to the flow of earnings. To address this concern, earnings must be matched with a corresponding representative measure of book value, or the resulting ROE will be distorted.

The need for this adjustment has been recognized in the financial literature.[25] Similarly, FERC has also cited the necessity to adjust year-end data from Value Line to reflect average values when computing earned rates of return.[26] In its June 2014 decision establishing new policies regarding ROE and confirmed in a recent September 2016 opinion, FERC relied directly on the expected earnings approach, which incorporates the exact same adjustment formula used in my Direct Testimony in this proceeding.[27] Similarly, the Virginia State Corporation

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[25] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 305-06.
[26] *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265 (2008).
[27] Opinion No. 531, 147 FERC ¶ 61,234 at P 146 (2014) and Opinion No. 551, 156 FERC ¶ 61,234 at P 239 (2016).

Commission has determined that it is appropriate to rely on average book equity, rather than year-end equity, when evaluating earned rates of return.[28]

Q27. WHAT OTHER EVIDENCE INDICATES THAT THE RECOMMENDATIONS OF THE ROE WITNESSES FAIL TO MEET REGULATORY STANDARDS?

A27. As discussed in my Direct Testimony, required equity returns for firms in the competitive sector of the economy are also relevant in determining the appropriate return to be allowed for rate-setting purposes.[29] The idea that investors evaluate utilities against the returns available from other investment alternatives – including the low-risk companies in my Non-Utility Group – is a fundamental cornerstone of modern financial theory. Aside from this theoretical underpinning, any casual observer of stock market commentary and the investment media quickly comes to the realization that investors' choices are almost limitless. It follows that utilities must offer a return that can compete with other risk-comparable alternatives, or capital will simply go elsewhere.

In fact, returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that the degree of risk, not the nature of the business, is relevant in evaluating an allowed ROE for a utility.[30] The cost of capital is based on the returns that investors could realize by putting their money in other alternatives, and the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment.

Q28. DID THE ROE WITNESSES PRESENT ANY OBJECTIVE EVIDENCE THAT WOULD SUPPORT A FINDING THAT YOUR NON-UTILITY

[28] *See, e.g., Case No. PUE-2014-00026,* Final Order at n. 84 (2014).
[29] McKenzie LGE Direct at 59-63.
[30] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

PROXY GROUP IS RISKIER THAN THE COMPANIES IN HIS PROXY GROUP?

A28. No. Mr. Walters, for instance, has simply alluded to a general assertion that companies in the non-utility proxy group "are subject to risks that are different from those affecting LG&E's regulated utility operations."[31] But my Direct Testimony did not contend that the specific operations or risk consideration of the companies in the Non-Utility Group are the same as those for utilities. Clearly, operating a worldwide enterprise in the beverage, pharmaceutical, retail, or food industry involves unique circumstances that are as distinct from one another as they are from an electric utility.

But as the Supreme Court recognized, investors consider the <u>expected returns</u> available from all these opportunities in evaluating where to commit their scarce capital. The simple observation that a firm operates in non-utility businesses says nothing at all about the <u>overall investment risks</u> perceived by investors, which is the very basis for a fair rate of return. So long as the risks associated with the Non-Utility Group are comparable to the Companies and other utilities the resulting DCF estimates provide a meaningful benchmark for the cost of equity. As demonstrated in my Direct Testimony, a comparison of objective risk measures demonstrates conclusively that the Non-Utility Group is regarded as less risky than KU and LG&E, making it a conservative benchmark for a fair ROE in this case.[32]

Q29. DR. WOOLRIDGE SAYS THAT ONE REASON YOUR NON-UTILITY ANALYSIS IS FLAWED IS THAT SUCH COMPANIES "DO NOT OPERATE IN A HIGHLY REGULATED ENVIRONMENT."[33] DOES THE

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[31] Walters Direct at 84.
[32] McKenzie LGE Direct, Table 7, at 62.
[33] Woolridge LGE Direct at 93.

FACT THAT UTILITIES ARE REGULATED SOMEHOW INVALIDATE THIS COMPARISON OF OBJECTIVE RISK INDICATORS?

A29. Absolutely not. While I agree that utilities operate under a regulatory regime that differs from firms in the competitive sector, any risk-reducing benefit of regulation is already incorporated in the overall indicators of investment risk presented in Table 7 to my Direct Testimony. The impact of regulation on a utility's investment risks is one of the key elements considered by credit rating agencies and investment advisory services, such as Standard & Poor's Corporation ("S&P") and Value Line, when establishing corporate credit ratings and other risk measures. As a result, the impact of regulatory protections is already reflected in my risk analysis. Meanwhile, the beta values supported by modern financial theory are premised on stock price volatility relative to the market as a whole, and are not dependent on an assessment of firm-specific considerations. As a result, the impact of regulatory differences on investment risk is accounted for in the published risk indicators relied on by investors and cited in my Direct Testimony.

Q30. WHAT WERE THE RESULTS OF YOUR ROE ANALYSIS FOR THE NON-UTILITY GROUP?

A30. As shown in Exhibit No. 11, page 3, the average ROEs for the Non-Utility group ranged from 10.0% to 11.2%. The midpoint of this range is 10.6%.

Q31. BASED ON YOUR COMPARISON OF THE ROE WITNESSES' RECOMMENDATIONS WITH ACCEPTED BENCHMARKS AND, IN LIGHT OF THE PROSPECT FOR HIGHER INTEREST RATES, WHAT DO YOU CONCLUDE?

A31. Based on these comparisons, the 8.75% ROE recommendation of Dr. Woolridge, the 9.00% recommendation of Mr. Baudino, and the 9.35% ROE recommendation of Mr. Walters are below any reasonable outcomes. One fundamental standard underlying the regulation of public utilities, as set forth by the Supreme Court's

Bluefield and *Hope* decisions, requires that the Companies must have the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments of similar risk if it is to maintain its financial flexibility and ability to attract capital.

If the utility is unable to offer a return similar to the returns available from other opportunities of comparable risk, investors will become unwilling to supply capital to the utility on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their cost of capital. Both of these outcomes violate regulatory standards.

Q32. WHAT OTHER PITFALLS ARE ASSOCIATED WITH AN ROE THAT FALLS BELOW THOSE AUTHORIZED FOR OTHER COMPARABLE COMPANIES?

A32. Adopting an ROE for the Companies that is well below the ROEs for comparable utilities could lead investors to view the Commission's regulatory framework as unsupportive, an outcome that would undermine investors' willingness to support future capital availability for investment in Kentucky. Security analysts study regulatory orders in order to advise investors where to invest their money. Moody's Investors Service ("Moody's) noted that, "[f]undamentally, the regulatory environment is the most important driver of our outlook."[34] Similarly, S&P concluded that "[t]he regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[35] Value Line summarizes these sentiments:

[34] Moody's Investors Service, "Regulation Will Keep Cash Flow Stable As Major Tax Break Ends," *Industry Outlook* (Feb. 19, 2014).
[35] Standard & Poor's Corporation, "Key Credit Factors For The Regulated Utilities Industry," *RatingsDirect* (Nov. 19, 2013).

> As we often point out, the most important factor in any utility's success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates. Harsh regulatory conditions can make it nearly impossible for the best run utilities to earn a reasonable return on their investment.[36]

Utilities and their investors must lock up large sums of capital and are exposed to many risks over the long time horizon when they invest in utility infrastructure. At the levels proposed by the ROE Witnesses, the ability of Kentucky utilities to attract and retain capital would be compromised. This would have a long-term, chilling effect on investors' willingness to support capital investment in utility infrastructure, not just for the Companies, but for all utilities in the state. On the other hand, if Commission actions instill confidence that the regulatory environment is supportive, investors will provide the necessary capital, which ultimately benefits customers and the service area economy.

II. RESPONSE TO DR. WOOLRIDGE

Q33. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR REBUTTAL TESTIMONY?

A33. My purpose here is to address Dr. Woolridge's mischaracterization of financial market conditions and the failings of his evaluation of a fair ROE for the Companies.

A. Capital Market Conditions

Q34. WHAT ARE DR. WOOLRIDGE'S VIEWS REGARDING CURRENT CAPITAL MARKET CONDITIONS?

A34. Dr. Woolridge summarizes his review of current capital market conditions by concluding that "interest rates and capital costs are at low levels and are likely to remain low for some time."[37] He then adds "[o]n this issue, I show that economists'

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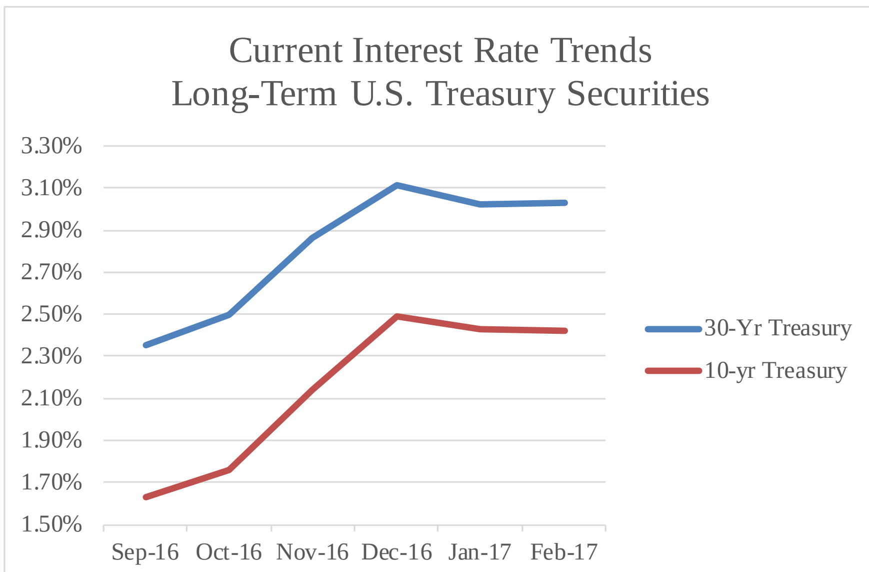
[36] Value Line Investment Survey, *Water Utility Industry*, January 13, 2017, p. 1780.
[37] Woolridge LGE Direct at 5.

forecasts of higher interest rates and capital costs, which are used by Mr. McKenzie, have been consistently wrong for a decade."[38]

Q35. DO RECENT TRENDS IN INTEREST RATES CONTRADICT THE OPINIONS OF DR. WOOLRIDGE?

A35. Yes. The figures below depict recent interest rate trends for long-term Treasury securities and public utility bonds.

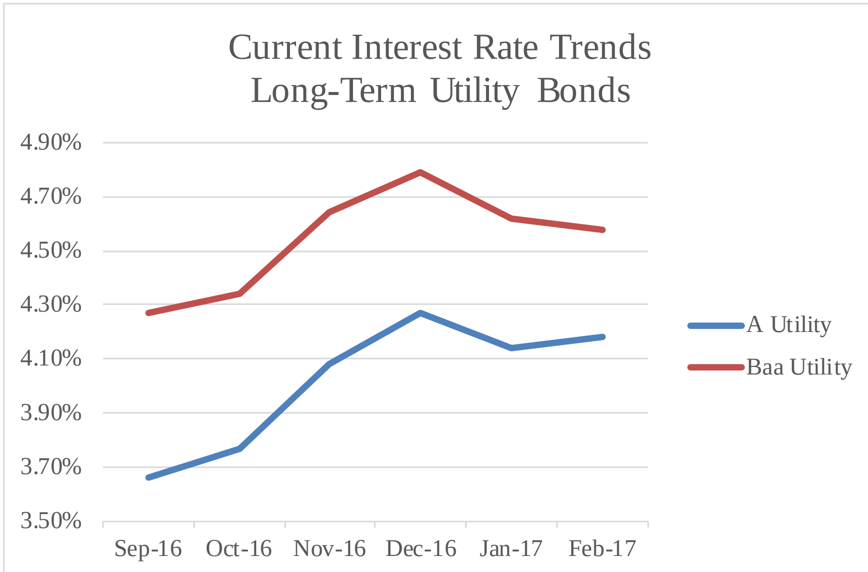
FIGURE R-3



Data Source: https://fred.stlouisfed.org/

[38] *Id.*

FIGURE R-4



Data Source: Moody's Investors Service at www.credittrends.com

As these charts indicate, long-term interest rates have increased since Fall 2016.

Q36. HAVE RECENT DECISIONS BY THE FEDERAL RESERVE REINFORCED INVESTOR SENTIMENT THAT INTEREST RATES WILL TREND HIGHER?

A36. Yes. On March 15, 2017 the Federal Reserve increased the target range for the Federal Funds rate by another 25 basis points. This is in addition to a similar increase on December 2016. More rate hikes by the Federal Reserve are anticipated in 2017.

Q37. ARE INTEREST RATE FORECASTERS STILL PROJECTING HIGHER LONG-TERM RATES FOR COMPANIES LIKE KU AND LG&E?

A37. Yes. As illustrated in Figure R-2 above, investors continue to anticipate that interest rates will increase significantly from present levels.

Q38. DR. WOOLRIDGE SUGGESTS THAT INTEREST RATE FORECASTS SHOULD BE IGNORED BY THE COMMISSION BECAUSE FORECASTS HAVE BEEN WRONG IN THE PAST. DO YOU AGREE?

A38. Absolutely not. I addressed this topic earlier. In estimating investors' required rate of return, what investors expect, not what actually happens, is what matters most. Any difference in actual rates as compared to analysts' forecasts is beside the point. What is most important is that investors share analysts' views when the forecasts were made and incorporate those views into their decision making process, not the actual rates that ultimately transpire.

Q39. DR. WOOLRIDGE DISCUSSES THE MARKET-TO-BOOK RATIO AND REACHES SEVERAL BOLD CONCLUSIONS IN THIS AREA. ARE HIS CONCLUSIONS REALISTIC?

A39. No. He says that a historical market-to-book ratio greater than one for the utility industry means that "for at least the last decade, returns on common equity have been greater than the cost of capital"[39] and "customers have been paying more than necessary to support an appropriate profit level for regulated utilities."[40]

Dr. Woolridge wants the Commission to sacrifice the Companies' financial strength to favor a theoretical ideal of M/B equaling unity. The Commission does not regulate utility stock market prices, and as discussed below, there are many leaps between his economic theory and reality. But if the theory is correct, then Dr. Woolridge is asking the Commission to order an ROE that would almost certainly lead to a capital loss on shareholders' investment in the Companies. From an economic perspective, such an action would violate the standards underlying a fair ROE.

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[39] *Id.* at 39.
[40] *Id.* at 40.

Q40. IS THERE A CLEAR LINK BETWEEN M/B FOR UTILITIES AND ALLOWED RATES OF RETURN?

A40. No. Underlying Dr. Woolridge's conclusions is the supposition that regulators should set an ROE to produce an M/B of approximately 1.0. This is fallacious. For example, Regulatory Finance: Utilities Cost of Capital noted that:

> The stock price is set by the market, not by regulators. The market-to-book ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce a market-to-book of 1.0, presumes that investors are irrational. They commit capital to a utility with a market-to-book in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is certainly not a realistic or accurate view of regulation.[41]

With M/B for most utilities above 1.0, Dr. Woolridge is suggesting that, unless book value grows rapidly, regulators should establish equity returns that will cause share prices to fall. Given the regulatory imperative of preserving a utility's ability to attract capital, this would be a truly nonsensical result. The M/B is determined by investors in the stock market, and a utility would be foreclosed from attracting capital if regulators were to push market-to-book to 1.0 while other firms command prices well in excess of 1.0 times book value.

Q41. IS THERE ANYTHING UNUSUAL ABOUT A STOCK PRICE EXCEEDING BOOK VALUE?

A41. No. In fact the majority of stocks currently sell substantially above book value. For example, Value Line reports that approximately 1,470 of the roughly 1,700 stocks it follows (including utilities and other industries) sell for prices in excess of book value.[42]

Q42. ARE THERE OTHER IMPORTANT FACTORS BEYOND ROE THAT EXPLAIN M/B FOR UTILITIES ABOVE 1.0?

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[41] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 376.
[42] www.valueline.com (retrieved Feb. 17, 2017).

A42. Yes. Although Dr. Woolridge's comparison would make it appear that utility ROEs are the cause for M/B greater than one, this contention entirely ignores accounting issues and other considerations. Consider, for example, the merger and acquisition activity that has significantly affected utility stock market prices in recent years. Investors know that many acquisitions have occurred and that significant premiums and large capital gains have been associated with those transactions. While earnings expectations are a part of market pricing, Dr. Woolridge's contention about direct causation between ROEs and market-to-book ratios is an extremely narrow view.

Q43. ARE ADJUSTMENTS BASED ON M/B A COMMON FEATURE IN DETERMINING ALLOWED ROES FOR UTILITIES?

A43. No. While arguments regarding the implications of a market-to-book greater than 1.0 are not uncommon, I am not aware of a single instance in recent history where a state regulator has approved a market-to-book adjustment in establishing a fair ROE. Meanwhile, FERC has explicitly recognized the fallacy of relying on market-to-book in evaluating cost of equity estimates. For example, the Presiding Judge in *Orange & Rockland* concluded, and the FERC affirmed that:

> The presumption that a market-to-book ratio greater than 1.0 will destroy the efficacy of the DCF formula disregards the realities of the market place principally because the market-to-book ratio is rarely equal to 1.0.[43]

The Initial Decision found that there was no support in FERC precedent for the use of market-to-book to adjust market derived cost of equity estimates based on the DCF model and concluded that such arguments were to be treated as “academic rhetoric” unworthy of consideration. Similarly, FERC rejected similar arguments from Dr. Woolridge more recently, concluding that “If, all else being equal, the regulator sets a utility’s ROE so that the utility does not have the

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[43] *Orange & Rockland Utilities, Inc.*, Initial Decision, 40 FERC ¶ 63,053, 1987 WL 118,352 (F.E.R.C.).

opportunity to earn a return on its book value comparable to the amount that investors expect that other utilities of comparable risk will earn on their book equity, the utility will not be able to provide investors the return they require to invest in that utility."[44]

Q44. IS DR. WOOLRIDGE'S M/B DISCUSSION RELEVANT TO THE SETTING OF THE COMPANIES' ROE IN THIS CASE?

A44. No. Even in the unlikely event that the long trail of breadcrumbs between Dr. Woolridge's theoretical postulations on M/B and allowed returns remained unbroken, his conclusion is directed at the wrong hypothesis. The question before the Commission is <u>not</u> what ROE will produce an M/B of 1.0 for utilities; rather, the question is what ROE will allow KU and LG&E to maintain access to capital and grant stockholders the opportunity to earn a fair return on investment vis-à-vis alternatives of comparable risk.

B. Discounted Cash Flow Model

Q45. WHAT ARE THE FUNDAMENTAL PROBLEMS WITH THE DCF ANALYSES CONDUCTED BY DR. WOOLRIDGE (AT 42-58)?

A45. There are numerous problems with the DCF analyses presented by Dr. Woolridge that lead to biased end results:

- One of the proxy groups relied on by Dr. Woolridge is defective due to flaws in the screening criteria and data he used, causing the exclusion of comparable utilities.
- Reliance on dividend growth rates and historical growth measures do not reflect a meaningful guide to investors' expectations.
- Dr. Woolridge discounts reliance on analysts' earnings per share ("EPS") growth forecasts as somehow biased, and fails to sufficiently recognize that it is investors' *perceptions and*

[44] *Martha Coakely, et al.,* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 129 (2015).

expectations that must be considered in applying the DCF model.

- Because Dr. Woolridge failed to test the reasonableness of model inputs, he incorrectly includes data that results in illogical cost of equity estimates.
- Dr. Woolridge's internal growth ("br") rates are downward biased because of computational errors and omissions.
- Rather than looking to the capital markets for guidance as to investors' forward-looking expectations, Dr. Woolridge applies the DCF model based on his own personal views.

As a result of these flaws and omissions, the resulting DCF cost of equity estimates are downward biased and fail to reflect investors' required rate of return.

Q46. DR. WOOLRIDGE APPLIED HIS ROE ANALYSES TO TWO GROUPS OF ELECTRIC UTILITIES, YOURS AND ONE BASED ON A DIFFERENT SET OF SELECTION CRITERIA. ARE THERE FLAWS IN HIS ELECTRIC PROXY GROUP?

A46. Yes. One of the selection criteria relied on by Dr. Woolridge required that at least 50% of the utility's revenues must come from regulated electric operations as reported by AUS Utility Report ("AUS").[45] There are several problems with this approach. First, the AUS report referenced by Dr. Woolridge is no longer in publication, with the last monthly edition being dated September 2016. This raises the distinct possibility that the AUS data used by Dr. Woolridge is stale, especially now that utilities have filed their SEC Form 10-Ks with data through December 2016.

Q47. DO YOU AGREE WITH DR. WOOLRIDGE THAT THE NATURE OF A UTILITY'S REVENUES IS A VALID CRITERION IN SELECTING A PROXY GROUP FOR THE COMPANIES?

A47. No. Dr. Woolridge failed to demonstrate how his subjective 50% revenue criterion translates into differences in the investment risks perceived by investors, while

[45] Woolridge LGE Direct at 25.

comparisons of objective indicators demonstrate that investment risks for the firms in my proxy groups are relatively homogeneous and comparable to the Companies.

Q48. DID DR. WOOLRIDGE DEMONSTRATE ANY NEXUS BETWEEN A SUBJECTIVE CRITERION BASED ON REGULATED REVENUES AND OBJECTIVE MEASURES OF INVESTMENT RISK?

A48. No. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful proxy group to estimate investors' required return is relative risk, not the source of the revenue stream or the nature of the asset base. Dr. Woolridge presented no evidence to demonstrate a connection between the subjective revenue criterion that he employed and the views of real-world investors in the capital markets. Nor did Dr. Woolridge provide any evidentiary support for his 50% threshold. Dr. Woolridge's testimony offers no explanation why a revenue cut-off of 50%, rather than, say, 40% or 60%, supposedly impacts a utility's operations sufficiently to justify its exclusion.

Moreover, due to differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as revenues and total assets, between regulated and non-regulated sources. As a result, even if one were to ignore the fact that there is no clear link between the nature of a utility's revenues or assets and investors' risk perceptions, it is generally not possible to accurately and consistently apply asset or revenue-based criteria. In fact, other regulators have rebuffed these notions, with FERC specifically rejecting arguments that utilities "should be excluded from the proxy group given the risk factors associated with its unregulated, non-utility business operations."[46]

Q49. CAN YOU ILLUSTRATE HOW A SCREEN BASED ON REVENUE COMPOSITION CAN LEAD TO AN ERRONEOUS CONCLUSION?

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[46] *Bangor Hydro-Elec. Co.*, 117 FERC ¶ 61,129 at PP 19, 26 (2006).

A49. Yes. Consider CenterPoint Energy, Public Service Enterprise Group, Sempra, and Vectren, which Dr. Woolridge omitted because regulated electric revenues were less than 50% of total revenue. However, after further inspection of their revenue composition, a different story is revealed. On page 1 of Exhibit JRW-4, Dr. Woolridge lists not only the level of regulated electric revenue, but also the level of regulated gas revenue. Gas distribution operations are regulated by the states in the same manner as electric operations, and there is no basis to distinguish between revenues from electric and gas utility operations, particularly when LG&E itself has both electric and gas operations. When gas revenues are combined with electric revenues, these companies all have regulated revenues that exceed the artificial, 50% threshold.[47]

Q50. DR. WOOLRIDGE ALSO EXCLUDED AVANGRID, ANOTHER COMPANY THAT IS IN YOUR GROUP. IS THERE A LOGICAL BASIS TO EXCLUDE AVANGRID?

A50. No. AVANGRID meets all of Dr. Woolridge's criteria: it is followed by Value Line, it has investment grade bond ratings, it has not cut or omitted any recent dividends, and long-term analyst growth forecasts are available. While AVANGRID is not included in the AUS report relied on by Dr. Woolridge to apply his revenue criterion, this is more likely to be a function of the cancellation of the publication and the resultant staleness of the remaining data. In any event, data found in AVANGRID's most recent SEC Form 10-K indicate that regulated operations contributed approximately 84% of total revenues.[48] For these reasons, Avangrid should properly be included in the proxy group in this case.

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[47] From Exhibit JRW-4, page 1, the combined electric and gas revenue percentages are 78% for CenterPoint, 74% for Sempra, 58% for Vectren, and 53% for Public Service Enterprise Group. In addition, Exelon's total regulated revenue of 47% arguably would merit inclusion in the group even under Dr. Woolridge's unsupported test.
[48] Avangrid reports regulated revenues of $5,030 million, out of total revenues of $6,018 million.

Q51. DO YOU BELIEVE THAT HISTORICAL TRENDS IN DIVIDENDS PER SHARE ("DPS") PROVIDE A MEANINGFUL GUIDE TO INVESTORS' EXPECTATIONS?

A51. No. As discussed at length in my direct testimony, it is investors' future expectations – and not actual, historical results – that determine the current price they are willing to pay for commons stocks. If past trends in DPS are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, which have experienced declining dividend payouts, earnings pressure, and, in many cases, significant write-offs.

Dr. Woolridge noted the pitfalls associated with historical growth measures. As he correctly observed:

> [T]o best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.[49]

As he acknowledged, historical growth rates can differ significantly from the forward-looking growth rate required by the DCF model:

> However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles).[50]

While past conditions for utilities serve to depress historical DPS growth rates, they are not representative of long-term expectations for the electric utility industry. Moreover, to the extent historical trends for electric utilities are meaningful, they

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[49] Woolridge LGE Direct at 49.
[50] *Id.*

are also captured in projected growth rates, such as those published by Value Line and Zacks Investment Research ("Zacks"), since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends.

Q52. DR. WOOLRIDGE ARGUES (AT 48) THAT THE GROWTH RATE COMPONENT IN THE DCF MODEL REFLECTS "THE LONG-TERM DIVIDEND GROWTH RATE." DO YOU AGREE THAT THIS IS WHAT INVESTORS ARE MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A52. No. Again, implementation of the DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, growth rates in DPS are not likely to provide a meaningful guide to investors' current growth expectations.

Q53. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A53. As documented in my direct testimony, future trends in EPS, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The continued success of investment services such as IBES,[51] Value Line, and Zacks, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in EPS is far more influential than trends in DPS. As explained in *New Regulatory Finance*:

[51] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth].[52]

The availability of projected EPS growth rates also is key to investors relying upon this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of EPS forecasts attests to their relative influence. The fact that analyst EPS growth estimates are routinely referenced in the financial media and in investment advisory publications implies that investors use them as a primary basis for their expectations. As observed in *New Regulatory Finance*:

> The sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Surveys of analytical techniques actually used by analysts reveal the dominance of earnings and conclude that earnings are considered far more important than dividends.[53]

While I did not rely solely on EPS projections in applying the DCF model,[54] my evaluation clearly supports greater reliance on EPS growth rate projections than other alternatives. Similarly, my Direct Testimony documented the KPSC's preference for relying on analysts' growth forecasts, which is supported by the findings of other regulatory agencies.[55]

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[52] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 298.
[53] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 302-303.
[54] As discussed in my direct testimony, I also examined the "br+sv", sustainable growth rates for the companies in my proxy groups.
[55] McKenzie LGE Direct at 35-56.

Q54. IS DR. WOOLRIDGE CONSISTENT IN HIS INSISTENCE THAT HISTORICAL GROWTH RATES AND TRENDS IN DPS MUST BE CONSIDERED IN APPLYING THE DCF MODEL?

A54. No. In testimony before FERC, Dr. Woolridge has applied the DCF model without any reference to historical trends or growth rates in DPS.[56] In the present case, despite his indictment of analysts' EPS growth projections, this data largely serves as the basis for his own DCF analysis. When selecting the final growth rates for both proxy groups referenced in his testimony, Dr. Woolridge gives "primary weight" to the projected EPS growth rates of Wall Street analysts.[57] So, while Dr. Woolridge complains vociferously about the suitability of analysts' EPS growth projections, he relies primarily on these same projections in reaching his ultimate DCF conclusions. His criticisms of the use of analysts' EPS growth projections ring hollow and are without merit in this light.

Q55. DO OTHER ROE WITNESSES ACKNOWLEDGE THE SUPERIORITY OF FORECASTED DATA, AS OPPOSED TO HISTORICAL DATA, IN THE DCF PROCESS?

A55. Yes. Mr. Walters concisely summarizes the issue when he states:

> As predictors of future returns, security analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data. That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence investors' decisions which are captured in observable stock prices than growth rates derived only from historical data.[58]

Mr. Baudino concurs that analysts' forecasts are superior:

> Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for dividend growth. Analysts' forecasts for

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[56] *See, e.g.*, *Testimony of J. Randall Woolridge*, Docket No. EL11-66-000, Exhibit SC-100.
[57] Woolridge LGE Direct at 56.
[58] Walters Direct at 34.

> earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.[59]

Q56. IS THE DOWNWARD BIAS IN DR. WOOLRIDGE'S HISTORICAL GROWTH MEASURES SELF EVIDENT?

A56. Yes, it is. As shown on page 3 of Exhibit JRW-10, thirty four of the historical growth rates reported by Dr. Woolridge for his electric proxy companies were 2.0% or less, including fourteen negative values.[60] A negative growth rate implies a cost of equity that falls below the utility's dividend yield which makes no economic sense. These outcomes illustrate the fact that Dr. Woolridge's historical growth measures provide no meaningful information regarding the expectations and requirements of investors.

Q57. DID DR. WOOLRIDGE ALSO INCLUDE LOW AND NEGATIVE GROWTH RATES IN HIS EXAMINATION OF PROJECTED GROWTH RATES?

A57. Yes, as shown on page 4 of Exhibit JRW-10, he included five growth rates at 1.5% or less in his analysis of projected growth rates for his electric proxy group.[61] Because these growth rates imply cost of equity estimates that are not materially higher than the yields on less risky utility bonds, they are not meaningful and should be excluded from his DCF analysis. On page 5 of Exhibit JRW-10, Mr. Woolridge includes two companies (Entergy Corporation and FirstEnergy Corporation) that have negative analyst projected growth rate estimates.

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[59] Baudino LGE Direct at 20.

[60] For the McKenzie Proxy Group shown on page 3 of Exhibit JRW-10, twenty one of the historical growth rates reported by Dr. Woolridge were 2.0% or less, including twelve negative values.

[61] For the McKenzie Proxy Group shown on page 4 of Exhibit JRW-10, two of the projected growth rates reported by Dr. Woolridge were 1.5% or less.

Q58. DID DR. WOOLRIDGE MAKE ANY EFFORT TO TEST THE REASONABLENESS OF THE INDIVIDUAL GROWTH ESTIMATES HE RELIED ON TO APPLY THE CONSTANT GROWTH DCF MODEL?

A58. No. Despite recognizing that caution is warranted in using historical growth rates, Dr. Woolridge simply calculated the average and median of the individual growth rates with no consideration for the reasonableness of the underlying data. In fact, as indicated above, many of the cost of equity estimates implied by Dr. Woolridge's DCF application make no economic sense. The table below highlights some of the individual company results that are incorporated into Dr. Woolridge's DCF analysis.

TABLE R-2
SELECT WOOLRIDGE COST OF EQUITY ESTIMATES

Company	Dividend Yield	Growth	DCF ROE
Entergy Corp.	4.80%	-5.90%	-1.10%
First Energy Corp.	4.50%	-3.60%	0.90%
MGE Energy, Inc.	2.00%	4.00%	6.00%
Consolidated Edison, Inc.	3.80%	2.40%	6.20%

Source: Exhibit JRW-10, pages 2 (90 Day Dividend Yield) and 5 (Mean Growth). DCF ROE is sum of dividend yield and growth.

With current triple-B utility interest rates in the 4.5%-5% range, the above results are not reasonable ROE outcomes. And as indicated in my direct testimony[62] and illustrated in Figure R-2 above, it is generally expected that long-term interest rates will rise as the Federal Reserve normalizes its monetary policies. As shown in the table below, the increase in debt yields anticipated by IHS Global Insight and the Energy Information Administration imply an average triple-B bond yield of approximately 5.86% over the period 2017-2021.

[62] McKenzie LGE Direct at 15-16.

TABLE R-3
BOND YIELD FORECAST

	2017-21
Projected Aa Utility Yield	
IHS Global Insight (a)	5.04%
EIA (b)	5.29%
Average	5.16%
Current Baa - Aa Yield Spread (c)	0.70%
Implied Baa Utility Yield	**5.86%**

(a) IHS Global Insight (Nov. 30, 2016).
(b) Energy Information Administration, Annual Energy Outlook 2017 (Jan. 5, 2017).
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Sep. 2016 - Feb. 2017.

Equity returns close to, or less than, this threshold are not credible. Yet, Dr. Woolridge factors them into his final conclusions, which biases his results downward.

Q59. WHAT APPROACH SHOULD DR. WOOLRIDGE HAVE USED TO EVALUATE LOW-END DCF ESTIMATES?

A59. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility’s common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, Dr. Woolridge should have evaluated his DCF results to eliminate estimates that are determined to be illogical when compared against the yields available to investors from less risky utility bonds. The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings. In Opinion No. 531, FERC concluded that, "The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt."[63] FERC has used 100 basis points above the six-month average public utility bond yield as an approximation of this threshold, but has also recognized that this is a flexible test.[64]

Q60. DR. WOOLRIDGE ARGUES YOUR ANALYSIS IS FLAWED BECAUSE OF YOUR "ASYMMETRICAL ELIMINATION OF DCF RESULTS."[65] IS THIS A VALID ARGUMENT?

A60. No. As discussed above, low-end outliers were evaluated against the observable returns available from long-term bonds. But the fact that there are numerous results that fail this test of reasonableness says nothing about the validity of estimates at the upper end of the range of results, and there is no basis to discard an equal number of values from the top of the range. While the upper end cost of equity estimate of 13.2% from my Exhibit No. 5 may exceed expectations for most utilities, the remaining low-end estimates in the 7.0% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provides a reasonable basis on which to evaluate investors' required rate of return.

Q61. DR. WOOLRIDGE RELIED ON SUSTAINABLE, "BR" GROWTH RATES (EXHIBIT JRW-10, P. 4). SHOULD THE COMMISSION PLACE ANY WEIGHT ON THESE VALUES?

A61. No. Dr. Woolridge's internal growth rates are downward biased because of computational errors and omissions. Dr. Woolridge based his calculations of the

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[63] Opinion No. 531 at P 122.
[64] *Id.*
[65] Woolridge LGE Direct at 75.

internal, "br" retention growth rate on data from Value Line. If the rate of return, or "r" component of the internal growth rate, is based on end-of-year book values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year.

Q62. WHAT OTHER CONSIDERATION LEADS TO A DOWNWARD BIAS IN DR. WOOLRIDGE'S CALCULATION OF INTERNAL, "BR" GROWTH?

A62. Dr. Woolridge ignored the impact of additional issuances of common stock in his analysis of the sustainable growth rate. Under DCF theory, the "sv" factor is a component designed to capture the impact on growth of issuing new common stock at a price above, or below, book value. As noted by Myron J. Gordon in his 1974 study:

> When a new issue is sold at a price per share P = E, the equity of the new shareholders in the firm is equal to the funds they contribute, and the equity of the existing shareholders is not changed. However, if P > E, part of the funds raised accrues to the existing shareholders. Specifically…[v] is the fraction of the funds raised by the sale of stock that increases the book value of the existing shareholders' common equity. Also, "v" is the fraction of earnings and dividends generated by the new funds that accrues to the existing shareholders.[66]

In other words, the "sv" factor recognizes that when new stock is sold at a price above (below) book value, existing shareholders experience equity accretion (dilution). In the case of equity accretion, the increment of proceeds above book value (P > E in Professor Gordon's example) leads to higher growth because it increases the book value of the existing shareholders' equity. In short, the "sv" component is entirely consistent with DCF theory, and the fact that Dr. Woolridge failed to consider the incremental impact on growth results in another downward bias to his "internal" growth rates, which should be given no weight.[67]

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[66] Myron J. Gordon, "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* (1974) at 31-32.

[67] In prior testimony before FERC, Dr. Woolridge incorporated an adjustment to correct for the downward bias attributable to end-of-year book values, and recognized the additional growth from new share issues by

Q63. DO OTHER ROE WITNESSES ACKNOWLEDGE THE VALIDITY OF THE "SV" TERM IN THEIR SUSTAINABLE GROWTH ANALYSIS?

A63. Yes. As shown in Exhibit CCW-7, Mr. Walters includes the "sv" term in his sustainable growth analysis.

Q64. DOES DR. WOOLRIDGE'S REFERENCE TO THE MEDIAN (AT 54) CORRECT FOR ANY UNDERLYING BIAS IN HIS HISTORICAL GROWTH RATES?

A64. No. The median is simply the observation with an equal number of data values above and below. For odd-numbered samples, the median relies on only a single number, *e.g.*, the fifth number in a nine-number set. Reliance on the median value for a series of illogical values does not correct for the inability of individual cost of equity estimates to pass fundamental tests of economic logic.

Q65. WHAT DO YOU CONCLUDE BASED ON YOUR REVIEW OF DR. WOOLRIDGE'S DCF ANALYSES?

A65. One glance at pages 3-5 of Exhibit JRW-10 and it is easy to see that Dr. Woolridge could basically have created any DCF growth rate that he wanted. These pages are a mishmash of historical and projected growth rates over varying time periods and not just for earnings, but for dividends and book value as well. There are literally hundreds of growth rates to choose from. The averages/medians for the two proxy groups referenced in his analysis range from 3.2% to 6.0%, and depending on personal whim, almost any DCF result could have been interpreted based on this data. For this reason, his DCF-based ROE recommendations are suspect and should be weighted accordingly.

Furthermore, trends in DPS are distorted by fundamental changes in industry financial policies and Dr. Woolridge failed to evaluate the underlying

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incorporating the "sv" component. *See, e.g., Testimony of J. Randall Woolridge*, FERC Docket No. EL-66 at Exhibit JRW-8, pp. 3-4 (2011).

reasonableness of individual growth rates. Finally, the calculations used to arrive at Dr. Woolridge's internal growth rates are flawed and incomplete because he did not adjust his end-of-year book values for growth in common equity over the year and because he completely left out the "sv" factor designed to capture the impact on growth of issuing new common stock. As a result, his DCF cost of equity estimates are biased downward and fail to reflect investors' required rate of return.

C. Capital Asset Pricing Model

Q66. WHAT IS THE FUNDAMENTAL PROBLEM ASSOCIATED WITH THE APPROACH THAT DR. WOOLRIDGE USED TO APPLY THE CAPM?

A66. The CAPM application presented by Dr. Woolridge was based entirely on *historical* rates of return, not current projections. Like the DCF model, risk premium methods – including the CAPM – are *ex-ante,* or forward-looking models based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM approach must be applied using data that reflects the expectations of actual investors in the market. The primacy of current expectations was recognized by Morningstar, one of the sources relied on by Dr. Woolridge to apply the CAPM:

> The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine cost of capital.[68]

By failing to look directly at the returns investors are currently requiring in the capital markets, as I did on Exhibit Nos. 7 and 8 to my direct testimony, the 7.9%

[68] Morningstar, *Ibbotson SBBI, 2013 Valuation Yearbook* at 21.

historical CAPM estimate developed by Dr. Woolridge[69] falls woefully short of investors' current required rate of return.

Q67. DR. WOOLRIDGE (AT 62) CHARACTERIZES HIS RISK PREMIUM AS *EX ANTE.* IS THIS AN ACCURATE ASSESSMENT?

A67. No. In order to be considered a forward-looking, *ex ante* estimate of the current market risk premium, the analysis must be predicated on investors' current expectations. Dr. Woolridge did not attempt to develop a market risk premium using current capital market information. Rather, he simply presented the results of various studies and surveys conducted in the past. Certain of these studies may have attempted to infer the equity risk premium using expected data at the time they were developed, but expectations at some point in the past are not equivalent to investors *ex ante* requirements in capital markets today.

Q68. IS THERE GOOD REASON TO ENTIRELY DISREGARD THE RESULTS OF HISTORICAL CAPM ANALYSES SUCH AS THOSE PRESENTED BY DR. WOOLRIDGE?

A68. Yes. Applying the CAPM is complicated by the impact of the Federal Reserve policies on investors' risk perceptions and required returns. As the Staff of the Florida Public Service Commission concluded regarding historical applications of the CAPM:

> [R]ecognizing the impact the Federal Government's unprecedented intervention in the capital markets has had on the yields on long-term Treasury bonds, staff believes models that relate the investor-required return on equity to the yield on government securities, such as the CAPM approach, produce less reliable estimates of the ROE at this time.[70]

[69] Woolridge LGE Direct at 67.
[70] *Staff Recommendation for Docket No. 080677-E1 - Petition for increase in rates by Florida Power & Light Company*, Docket No. 080677-E1, at 280 (Dec. 23, 2009).

Similarly, in *Orange & Rockland Utilities*, FERC determined that CAPM methodologies based on historical data were suspect because whatever historical relationships existed between debt and equity securities may no longer hold.[71] FERC concluded that historical risk premiums are downward biased given recent trends of low yields for Treasury bonds.[72]

As a result, there is every indication that the historical CAPM approach fails to fully reflect the risk perceptions of real-world investors in today's capital markets, which would violate the standards underlying a fair rate of return by failing to provide an opportunity to earn a return commensurate with other investments of comparable risk.

Q69. DID DR. WOOLRIDGE ALSO RECOGNIZE THE FRAILTIES OF HIS HISTORICAL CAPM APPROACHES?

A69. Yes. Dr. Woolridge noted that *ex-post*, historical rates of return "are not the same as *ex ante* expectations," and observed that, "The use of historical returns as market expectations has been criticized in numerous academic studies."[73] Dr. Woolridge admitted that "risk premiums can change over time … such that *ex post* historical returns are poor estimates of *ex ante* expectations."[74] Finally, Dr. Woolridge conceded, that his historical CAPM approach provides "a less reliable indication of equity cost rates for public utilities."[75]

Q70. IS THERE EVIDENCE THAT THE STUDIES REFERENCED BY DR. WOOLRIDGE DO NOT REFLECT INVESTORS' EXPECTATIONS?

A70. Yes. The vast majority of the equity risk premium findings reported by Dr. Woolridge do not make economic sense and contradict his own testimony. For

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[71] *See Orange & Rockland Utils., Inc.*, 40 FERC ¶ 63,053 at 65,208-09 (1987), *aff'd*, Opinion No. 314, 44 FERC ¶ 61,253 at 65,208 (2008).
[72] *See New York Independent System Operator, Inc.*, 146 FERC ¶ 61,043 at P 105 (2014).
[73] Woolridge LGE Direct at 63.
[74] *Id.* at 63.
[75] *Id.* at 42.

example, page 5 of Dr. Woolridge's Exhibit JRW-11 reveals that well over half of the historical studies included in Dr. Woolridge's review found market equity risk premiums of approximately 5.0% or below. This was also true for nearly half of the individual risk premium studies that Dr. Woolridge classified as "more recent."[76] But combining a market equity risk premium of 5.0% with Dr. Woolridge's 4.0% risk-free rate results in an indicated cost of equity for the market as a whole of 9.0%, which barely exceeds his ROE recommendation for KU and LG&E in this case.

Meanwhile, after noting that beta is the only relevant measure of investment risk under modern capital market theory, Dr. Woolridge concluded that his comparison of beta values (Exhibit JRW-8) indicates that investors' required return on the market as a whole should exceed the cost of equity for electric utilities.[77] Based on Dr. Woolridge's own logic, it follows that a market rate of return that does not significantly exceed his own downward biased ROE recommendation has no relation to the current expectations of real-world investors. The fact that much of his CAPM "evidence" violates the risk-return tradeoff that is fundamental to financial theory clearly illustrates the frailty of Dr. Woolridge's analyses.

Q71. ARE THERE OTHER SHORTCOMINGS ASSOCIATED WITH THE SOURCES CITED BY DR. WOOLRIDGE?

A71. Yes. For example, the *Fernandez* survey is the result of a mass solicitation to more than 23,000 email addresses, out of which approximately 6,900 responses were received.[78] While many of the responses were undoubtedly from informed professionals, there is no ability verify the experience or familiarity of the

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[76] Exhibit JRW-11, p. 6.
[77] Woolridge LGE Direct at 41.
[78] Pablo Fernandez, Alberto Ortiz, and Isabela Fernandez Acin, "Market Risk Premium used in 71 Countries in 2016: a survey with 6,923 answers," (May 2016) https://papers.ssrn.com/sol3/Delivery.cfm/SSRN_ID2776636_code12696.pdf?abstractid=2776636&mirid=1&type=2 (last visited Mar. 1, 2016). While Dr. Wilson bases his testimony on stale information from 2008 and 2009, the current *Fernandez* survey is comparable to earlier renditions.

respondents with the subject matter. In addition, the wording of the surveys is imprecise and open to interpretation. For example, the 2016 survey simply asks, "The Market Risk Premium that I am using in 2016 for USA is _____%,"[79] which is entirely unclear. The respondent has no idea whether he or she is being queried for a risk premium during 2016, or over some other time period; nor is the basis on which the risk premium is calculated even specified.[80]

Meanwhile, the approach used to derive a market risk premium in *Damodaran* forces the growth rate for all competitive firms to a constant long-term rate after five years. In addition, *Damodaran* inexplicably assumes that this long term rate of growth will equal the current yield on U.S. Treasury bonds, or 2.39% in its current rendition.[81] This is significantly below even the GDP growth rate range of 3.0% to 5.0% advocated by Dr. Woolridge.[82] There is no logical link between investors' long-term growth expectations for common stocks and the current Treasury bond yield, and I know of no credible source of investment guidance that is expecting growth for all companies in the economy to collapse to 2.39% over the next five years.

The fundamental problem with Dr. Woolridge's approach is that instead of looking directly at an equity risk premium based on current expectations – which is what is required in order to properly apply the CAPM and is the approach I took – he undertakes an unrelated exercise of compiling selected computations culled from the historical record. In short, while there are many potential definitions of the equity risk premium, the only relevant issue for application of the CAPM in a

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[79] *Id.*
[80] One respondent to the *Fernandez* survey characterized the imprecision and ambiguity this way: "You don't define exactly what you mean by "Market Risk Premium". Different authorities define it in different ways. Is it expected return over short-term government securities (*e.g.,* 30 or 90 day T-Bills), or longer-term government bonds?" *Id.*
[81] http://www.stern.nyu.edu/~adamodar/pc/implprem/ERPMar17.xls (last visited Mar. 1, 2017).
[82] Woolridge LGE Direct at 81.

regulatory context is the return investors currently expect to earn on money invested today in the risky market portfolio versus the risk-free U.S. Treasury alternative.

Q72. WAS DR. WOOLRIDGE (EXHIBIT JRW-11, PP. 5-6) JUSTIFIED IN RELYING ON GEOMETRIC MEANS AS A MEASURE OF AVERAGE RATE OF RETURN WHEN APPLYING THE HISTORICAL CAPM?

A72. No. While both the arithmetic and geometric means are legitimate measures of average return, they provide different information. Each may be used correctly, or misused, depending upon the inferences being drawn from the numbers. The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The arithmetic mean measures what the expected return would have to be each period to achieve the realized change in value over time.

In estimating the cost of equity, the goal is to replicate what investors expect going forward, not to measure the average performance of an investment over an assumed holding period. When referencing realized rates of return in the past, investors consider the equity risk premiums in each year independently, with the arithmetic average of these annual results providing the best estimate of what investors might expect in future periods. *New Regulatory Finance* had this to say:

> The best estimate of expected returns over a given future holding period is the arithmetic average. *Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital.* There is no theoretical or empirical justification for the use of geometric mean rates of returns as a measure of the appropriate discount rate in computing the cost of capital or in computing present values.[83]

Similarly, *Morningstar* concluded that:

> For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple

[83] Roger A. Morin, "New Regulatory Finance" *Public Utilities Reports, Inc.* (2006) at 116-117, (emphasis added).

> difference of the arithmetic means of stock market returns and riskless rates is the relevant number. … The geometric average is more appropriate for reporting past performance, since it represents the compound average return.[84]

Q73. WHAT DOES THIS IMPLY WITH RESPECT TO DR. WOOLRIDGE'S CAPM ANALYSES?

A73. For a variable series, such as stock returns, the geometric average will <u>always</u> be less than the arithmetic average. Accordingly, Dr. Woolridge's reference to geometric average rates of return provides yet another element of built-in downward bias.

Q74. DR. WOOLRIDGE REFERENCES CAPITAL MARKET TRENDS. IS IT APPROPRIATE TO CONSIDER ANTICIPATED CAPITAL MARKET CHANGES IN APPLYING THE CAPM?

A74. Yes. As discussed in my direct testimony, there is widespread consensus that interest rates will increase materially as the economy strengthens. Accordingly, in addition to the use of current bond yields, I also applied the CAPM and ECAPM approaches based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip.

D. Other ROE Issues

Q75. PLEASE RESPOND TO DR. WOOLRIDGE'S ARGUMENT THAT THERE IS NO BASIS TO INCLUDE A FLOTATION COST ADJUSTMENT.

A75. The need for a flotation cost adjustment to compensate for past equity issues is recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must

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[84] Morningstar, *Ibbotson SBBI 2013 Valuation Yearbook* at 56.

consider total equity, including retained earnings.[85] Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

> Another controversy is whether the underpricing allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[86]

Q76. IS THERE ANY MERIT TO DR. WOOLRIDGE'S ARGUMENT (AT 89) THAT FLOTATION COSTS CAN BE IGNORED BECAUSE THEY CANNOT BE PRECISELY QUANTIFIED?

A76. No. As discussed in my direct testimony,[87] the costs incurred to issue new debt securities are recorded on the financial books of the utility and routinely recovered from customers without controversy. While equity flotation costs are every bit as necessary to supply invested capital, they are not recorded on the utility's books, so there is no precise accounting for these costs. Nevertheless, they represent necessary and legitimate expenses incurred to obtain the equity capital invested in utility plant, and unless some provision is made for their recovery, investors will not be offered an opportunity to fully earn their required ROE. The need to consider flotation costs has been documented in the financial literature and Dr. Woolridge's observations provide no basis to ignore issuance costs.

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[85] E.F. Brigham, D.A. Aberwald, and L.C. Gapenski, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, May, 2, 1985.
[86] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 335.
[87] McKenzie LGE Direct at 55-59.

Q77. PLEASE RESPOND TO DR. WOOLRIDGE'S SPECIFIC CRITICISMS OF YOUR FLOTATION COST ADJUSTMENT (AT 89-92).

A77. Flotation cost adjustments are supported by recognized regulatory textbooks and based on research reported in the academic literature, and the lack of a precise accounting of past issuance expenses necessary to raise the common equity capital invested in KU and LG&E provides no basis to ignore a flotation cost adjustment.

Meanwhile, Dr. Woolridge mistakenly claims that a flotation cost adjustment "is necessary to prevent dilution of the existing shareholders."[88] In fact, a flotation cost adjustment is required in order to allow the utility the opportunity to recover the issuance costs associated with selling common stock. Dr. Woolridge's observation about the level of market-to-book ratios (at 88) may be factually correct, but it has nothing to do with flotation costs. The fact that market prices may be above book value does not alter the fact that a portion of the capital contributed by equity investors is not available to earn a return because it is paid out as flotation costs. Even if the utility is not expected to issue additional common stock, a flotation cost adjustment is necessary to compensate for flotation costs incurred in connection with past issues of common stock.

Dr. Woolridge's argument (at 91) that flotation costs are "not out-of-pocket expenses" is simply wrong. Dr. Woolridge apparently believes that if investors in past common stock issues had paid the full issuance price directly to the utility and the utility had then paid underwriters' fees by issuing a check to its investment bankers, that flotation cost would be a legitimate expense. Dr. Woolridge's observation merely highlights the absence of an accounting convention to properly accumulate and recover these legitimate and necessary costs.

[88] Woolridge LGE Direct at 90.

Q78. HAVE OTHER REGULATORS RECOGNIZED THAT FLOTATION COSTS ARE A LEGITIMATE CONSIDERATION IN ESTABLISHING A FAIR ROE?

A78. Yes. For example, in Docket No. UE-991606 the Washington Utilities and Transportation Commission concluded that a flotation cost adjustment of 25 basis points should be included in the allowed return on equity:

> The Commission also agrees with both Dr. Avera and Dr. Lurito that a 25 basis point markup for flotation costs should be made. This amount compensates the Company for costs incurred from past issues of common stock. Flotation costs incurred in connection with a sale of common stock are not included in a utility's rate base because the portion of gross proceeds that is used to pay these costs is not available to invest in plant and equipment.[89]

Similarly, the South Dakota Public Utilities Commission has recognized the impact of issuance costs, concluding that, "recovery of reasonable flotation costs is appropriate."[90] Another example of a regulator that approves common stock issuance costs is the Mississippi Public Service Commission, which routinely includes a flotation cost adjustment in its Rate Stabilization Adjustment Rider formula.[91] The Public Utilities Regulatory Authority of Connecticut[92] and the Minnesota Public Utilities Commission[93] have also recognized that flotation costs are a legitimate expense worthy of consideration in setting a fair ROE.

Q79. IS THERE ANY MERIT TO DR. WOOLRIDGE'S ARGUMENT (AT 84-85) THAT THE SIZE PREMIUM DOES NOT APPLY TO UTILITY COMMON STOCKS?

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[89] *Third Supplemental Order*, WUTC Docket No. UE-991606, et al., p. 95 (September 2000).
[90] *Northern States Power Co*, EL11-019, Final Decision and Order at P 22 (2012).
[91] *See*, *e.g.*, Entergy Mississippi, Inc., Formula Rate Plan Rider (Apr. 15, 2015), http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf (last visited Mar. 16, 2017).
[92] *See*, *e.g.*, Docket No. 14-05-06, Decision (Dec. 17, 2014) at 133-134.
[93] *See*, *e.g.*, Docket No. E001/GR-10-276, Findings of Fact, Conclusions, and Order at 9.

A79. No. There is no credible basis to conclude that utilities are immune from the well-documented relationship between smaller size and higher realized rates of return. For example, Dr. Woolridge places significant weight on a 1992 study by Annie Wong,[94] but a closer examination of this research reveals that it is largely inconclusive, and inconsistent with the CAPM. In fact, her results demonstrate no material difference between utilities and industrial firms with respect to size premiums, and her study finds no significant relationship between beta and returns, which contradicts modern portfolio theory and the CAPM. A more recent study published in the Quarterly Review of Economics and Finance reconsiders Wong's evidence and concludes that "new information . . . indicates there is a small firm effect in the utility sector."[95]

Q80. DR. WOOLRIDGE CRITICIZES THE MARKET RETURN THAT YOU USE IN YOUR CAPM AND ECAPM ANALYSES CLAIMING THAT "AS INDICATED IN RECENT RESEARCH, THE LONG-TERM EARNINGS GROWTH RATES OF COMPANIES ARE LIMITED TO THE GROWTH RATE IN GDP" (AT 82). WHAT IS YOUR RESPONSE TO THIS CLAIM?

A80. I address this claim later in my response to Mr. Walters. There, I show that the theoretical proposition that growth rates for all firms converge to overall growth in the economy over the very long horizon does not guide investors' views, and growth rates for companies can and do exceed GDP growth.

Q81. DR. WOOLRIDGE SAYS THAT YOUR EXPECTED EARNINGS APPROACH IS FLAWED DUE TO UNREGULATED OPERATIONS OF THE PROXY GROUPS AND DUE TO DIFFERENCES IN M/B.[96] DO YOU AGREE WITH THIS ASSESSMENT?

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[94] *Id.* at 84-85.

[95] Thomas M. Zepp, "Utility stocks and the size effect—revisited," Quarterly Review of Economics and Finance, 43 (2003) 578-582.

[96] Woolridge LGE Direct at 92.

A81. Not at all. The appeal of the expected earnings approach is that it does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior. While companies in the proxy groups may have varying levels of unregulated operations, they have all been judged to be of comparable overall risk and this condition overrides specific differences between them.

Again, M/B have no place in applying the expected earnings approach. Traditional applications of the expected earnings approach do not involve an M/B adjustment. Nor is such an adjustment recommended in recognized texts such as *New Regulatory Finance.*[97] FERC has also rejected similar arguments raised by Dr. Woolridge, finding that, "considering market-to-book ratios in an expected earnings study is inconsistent with the purpose of the comparable earnings model."[98]

Q82. DR. WOOLRIDGE CRITICIZES YOUR USE OF A LOW-RISK GROUP OF NON-UTILITY COMPANIES AS AN ROE CHECK OF REASONABLENESS (AT 92-93). ARE HIS CRITICISMS JUSTIFIED?

A82. Not at all. The implication that an estimate of the required return for firms in the competitive sector of the economy is not useful in determining the appropriate return to be allowed for rate-setting purposes is wrong and inconsistent with reality, investor behavior, and the *Bluefield* and *Hope* decisions. In fact, returns in the competitive sector of the economy form the very underpinning for utility ROEs

[97] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006).
[98] *Martha Coakely, et al.*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 132 (2015).

because regulation purports to serve as a substitute for the actions of competitive markets.

The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives, which include all other securities available in the stock, bond or money markets. Consistent with this view, Dr. Woolridge noted the Supreme Court's economic standards and concluded that the fair rate of return on equity should be "comparable to returns investors expect to earn on other investments of similar risk."[99] Clearly the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment and there are a plethora of other "investments of comparable risk" available to investors beyond those in the utility industry.

True enough, utilities are sheltered from competition, but they undertake other obligations and lose the ability to set their own prices and decide when to exit a market. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility.[100]

Q83. DOES THE MARCH 10, 2015 REPORT FROM MOODY'S CITED BY DR. WOOLRIDGE (AT 71) SUPPORT A DRAMATIC DROP IN THE COMPANIES' ALLOWED RETURN FROM THOSE CURRENTLY BEING AUTHORIZED FOR COMPARABLE UTILITIES?

A83. No. The Moody's report discusses only very generally the impacts of a "slow" decline in utilities' authorized ROEs, and how regulators may lower authorized ROEs without harming utilities' cash flow, such as by "targeting depreciation." The Moody's report does not identify a cost of equity for regulated utilities at all, much less discuss a cost of equity for KU or LG&E, which is not even mentioned

[99] Woolridge LGE Direct at 3.
[100] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

in the report. In my view, the Moody's report offers no relevant information about a fair ROE in this proceeding, and it certainly does not support the values recommended by the ROE Witnesses.

Q84. DOES THE MOODY'S REPORT INDICATE THAT EQUITY INVESTORS WOULD NOT BE CONCERNED IF THE COMPANIES' ROES WERE LOWERED TO THE LEVELS RECOMMENDED BY THE ROE WITNESSES?

A84. No. I believe no one can make such an inference based on this report.[101] First, it is important to note that the primary mission of credit rating agencies like Moody's is to provide *debt holders* with an accurate benchmark of the relative risks of default associated with long-term bonds and other debt securities. As the report cited by Dr. Woolridge clearly observes, Moody's evaluation is premised "from the perspective of a probability of a default and expected loss given default."

Bondholders, the constituency represented by Moody's, do not share in a utility's net income or profits. As a result, Moody's focus is on cash flows, which are viewed "as a more important rating driver."[102] On the other hand, *equity investors* are intensely focused on the ability of the utility to generate earnings, dividends and growth. This difference in the characteristics and priorities between debt and equity securities gives rise to the considerable distinction in the risks faced by debt holders and equity investors. While a moderate and gradual downturn in ROEs may not pose an immediate threat to the cash flow protection underlying the credit ratings on a utility's debt, it would have an immediate, negative impact on returns to common stockholders.

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[101] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," *Sector In-Depth* (March 2015).
[102] *Id.*

E. Capital Structure

Q85. DO YOU AGREE WITH DR. WOOLRIDGE'S PROPOSAL TO IMPOSE A HYPOTHETICAL CAPITAL STRUCTURE ON KU AND LG&E?

A85. No. As I stated in my Direct Testimony, the Companies' requested capital structures are reasonable. They fall well within the range of capitalizations maintained by the firms in the proxy group of utilities and are consistent with the capitalizations maintained by other electric utility operating companies based on data at year-end 2015. I have updated the operating company data through 2016 and the results are shown in Rebuttal Exhibit No. 15. Electric utility operating company equity levels range from 41.5% to 73.3%, with an average of 52.7%. This is comparable to the 53.28% and 53.27% equity ratios proposed by KU and LG&E, respectively, and reinforces my conclusion that the Companies' requested capital structures fall within a reasonable range.

Q86. DR. WOOLRIDGE RECOMMENDS A HYPOTHETICAL CAPITAL STRUCTURE WITH 50% EQUITY. DOES HE PROVIDE ANY ANALYSIS TO SUPPORT HIS PROPOSAL?

A86. No. He simply says "I am using a capital structure with an imputed common equity ratio of 50.0%."[103] Dr. Woolridge provides no objective evidence as to why the particular equity ratio he has chosen is justified, or more appropriate than, say, a 45% equity level or a 55% equity level. His recommendation appears to lack any evidentiary support.

Q87. HOW DO THE COMPANIES' REQUESTED CAPITAL STRUCTURES COMPARE TO THOSE LAST AUTHORIZED BY THE KPSC?

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[103] Woolridge LGE Direct at 34.

A87. The capital structures requested in the current cases contain less equity than was specified in settlements approved by the KPSC in 2012, which authorized an equity level for KU of 53.7% and 55.64% for LG&E.[104]

Q88. WHAT CAPITAL STRUCTURES DO THE OTHER ROE WITNESSES RECOMMEND IN THIS CASE?

A88. Mr. Baudino and Mr. Walters both accept the Companies' proposed capital structures.

Q89. DR. WOOLRIDGE RAISES THE SPECTER OF "DOUBLE LEVERAGE" IN HIS TESTIMONY. IS THIS A LEGITIMATE CONCERN?

A89. No. The Companies' requested equity ratios are well within the range of capitalizations maintained by the firms in the proxy group of utilities and are consistent with the capitalizations maintained by other electric utility operating companies. Dr. Woolridge compares the Companies' capital structures to that of their parent, PPL Corporation, but a holding company is not a regulated utility and the regulator does not have the jurisdiction to control its earnings, any more than they can regulate private investors who own common stock.

In addition, investors and bond rating agencies know that a double leverage adjustment makes it difficult, if not impossible, for the utility to actually earn the allowed return. Investors have choices available to them, both in other utilities and the plethora of non-utility options, and regulatory actions that thwart a utility's ability to actually earn its allowed ROE would undermine access to capital. Thus, decreasing the realistically achievable return through a double leverage adjustment, or the potential application of such an adjustment in the future, would harm customers in the long-run because the utility would not be able to maintain its

[104] Kentucky Public Service Commission, Docket Nos. 2012-00221 and 2012-00222, Final Orders Dec. 20, 2012. The Companies' most recent rate cases (Docket Nos. 2014-00371 and 2014-00372) did not specify a capital structure.

financial integrity and raise capital on reasonable terms. There is no justification to consider double leverage in this case, particularly given the adverse impact it has on the risk perceptions of investors and bond rating agencies.

F. Gas Utility ROE

Q90. DR. WOOLRIDGE RECOMMENDS AN ROE FOR LG&E'S GAS OPERATIONS (AT 8.70%) THAT IS 5 BASIS POINTS LOWER THAN THE ROE HE RECOMMENDS FOR ITS ELECTRIC OPERATIONS. DO YOU AGREE WITH THIS APPROACH?

A90. No. The KPSC has always considered LG&E to be an integrated utility and, on that basis, has always set one ROE to apply to the entire company. This is why I limited my proxy group to companies with both electric and gas operations. As I discussed earlier with regard to the DCF analysis for his electric groups, a review of pages 3-5 of Exhibit JRW-10 make it clear that Dr. Woolridge could have created any gas company DCF result that he wanted. It is more coincidence than reality that his gas company ROE ended up where it did, five basis points lower than his electric company outcome. Dr. Woolridge provides no explanation to support the premise that separate ROEs are appropriate for LG&E's integrated utility operations. As a result, his conclusions in this area lack credibility and should be disregarded.

Q91. DID THE OTHER ROE WITNESSES PROPOSE SEPARATE ROES FOR LG&E'S INTEGRATED UTILITY OPERATIONS?

A91. No. Like me, Mr. Baudino and Mr. Walters propose a single ROE applicable across the integrated utility operations of LG&E.

III. RESPONSE TO MR. BAUDINO

Q92. HOW DID MR. BAUDINO ARRIVE AT HIS RECOMMENDED COST OF EQUITY?

A92. Mr. Baudino recommended an ROE of 9.00% based exclusively on his application of the constant growth DCF model. He included a CAPM analysis for "additional information" but did not incorporate the results of the CAPM directly in his recommendation.[105] Mr. Walters applied these methods to the same proxy group I did, but for three utilities that he excluded due to perceived data issues.[106]

Q93. WHAT IS YOUR ASSESSMENT OF MR. BAUDINO'S ROE TESTIMONY AND RECOMMENDATION?

A93. Mr. Baudino's recommendation is not realistic. Several specific factors detract from his analysis. First and foremost, Mr. Baudino fails to apply sufficient checks of reasonableness to test his DCF results. His CAPM approach is significantly flawed and he ignores other accepted benchmarks such as the utility risk premium, expected earnings, and ECAPM methodologies, or a review of non-utility outcomes. Had Mr. Baudino employed these other approaches, he would have seen that his DCF-based result was not reasonable.

A. Discounted Cash Flow Model

Q94. WHAT ARE THE SPECIFIC DEFECTS THAT YOU HAVE IDENTIFIED IN MR. BAUDINO'S DCF ANALYSIS?

A94. While Mr. Baudino's application of the DCF model is fairly straightforward, there are several problems with his approach. First, I do not agree with his decision to eliminate three companies from my proxy group. Second, he repeats the mistakes made by Dr. Woolridge in giving weight to DPS growth rates and in conducting an incomplete "br" growth study. Finally, his DCF results are based on a decision to average all individual growth rates together and compute a single ROE estimate for each growth rate source. This approach masks the presence of extreme data and biases his results downward.

[105] Baudino LGE Direct at 3.
[106] Mr. Baudino eliminated Avangrid, Inc., Entergy Corp, and PPL Corp.

Q95. PLEASE ELABORATE ON YOUR DISAGREEMENT WITH MR. BAUDINO'S PROXY GROUP?

A95. I do not agree with Mr. Baudino's decision to exclude three eligible utilities from my proxy group in forming his sample. He rejects AVANGRID because "there is not enough Value Line information to include this company in the proxy group."[107] AVANGRID is a major utility with a market capitalization of $12 billion. Its subsidiaries are well known to investors and include Central Maine Power, New York State Electric & Gas, Rochester Gas and Electric, and United Illuminating. AVANGRID has stable dividend policies, and while Value Line may not currently report projected growth rates, this data is available from comparable sources such as Zacks and IBES, which were both relied on by Mr. Baudino. Indeed, Mr. Baudino applied the DCF model to other firms in his proxy group that lacked meaningful growth rate estimates from a single source. It would have been easy to substitute "N/A" for Avangrid's Value Line growth rate and continue the DCF calculation with the other two growth rate sources. This approach is no different that Mr. Baudino applied to Avista Corporation, where he input "N/A" for its missing Zacks rate.[108]

The same argument applies to Mr. Baudino's decision to discard Entergy Corp. and PPL Corp. Instead of removing the entire company from his analysis in the face of low or missing individual growth rates, Mr. Baudino should have included the company in the proxy group while disregarding any illogical growth terms.

[107] Baudino LGE Direct at 16-17.

[108] For example, Mr. Baudino applied the DCF model to Avista Corporation using data from Value Line and IBES, while reflecting "N/A" for a missing growth rate from Zacks. Exhibit RAB-5, page 1.

Q96. MR. BAUDINO CONSIDERED DIVIDEND DATA IN THE GROWTH RATE PORTION OF HIS DCF ANALYSIS. IS THIS APPROACH LIKELY TO DISTORT HIS DCF RESULTS?

A96. Yes. As discussed earlier in my response to Dr. Woolridge, growth rates in DPS are not likely to provide a meaningful guide to investors' current growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in EPS is far more influential than trends in DPS.

Q97. MR. BAUDINO ALSO PRESENTED SUSTAINABLE, "BR" GROWTH RATES (EXHIBIT RAB-5, P. 1). SHOULD THE KPSC PLACE ANY WEIGHT ON THESE VALUES?

A97. No. In the same way as I explained earlier in my rebuttal to Dr. Woolridge, Mr. Baudino's "br" growth rates are downward biased because he failed to recognize the impact of year-end returns reported by Value Line. Furthermore, like Dr. Woolridge, Mr. Baudino ignored the impact of additional issuances of common stock in his analyses of the sustainable growth rate. Because Mr. Baudino ignored these adjustment in this case, his internal, "br" growth rates are distorted and should be ignored.

Q98. ARE THERE OTHER PROBLEMS WITH MR. BAUDINO'S DCF ANALYSIS?

A98. Yes. Another flaw in Mr. Baudino's DCF analyses was his decision to average all individual growth rates together, and then compute a single DCF estimate for each growth rate source. Each growth rate represents a stand-alone estimate of investors' future expectations, and each value should be evaluated on its own merits. The fact that an average of several growth rates might produce a DCF estimate that could be considered reasonable does not absolve the need to evaluate each underlying growth rate separately.

For example, consider a utility with a dividend yield of 3.5% and three hypothetical growth estimates of 0.0%, 6.5%, and 14.0%. Under Mr. Baudino's method, the DCF estimate would be computed by adding the 6.8% average of the three individual growth rates to the dividend yield, resulting in a cost of equity estimate of 10.3%. The problem with this method is that it disguises the fact that two of the underlying growth rates – 0.0% and 14.0% – do not provide a meaningful guide to investors' expectations. Rather than averaging the good with the bad, each implied cost of equity estimate (in this example, 3.5%, 10.0%, and 17.5%) should be evaluated on a stand-alone basis.[109] Mr. Baudino simply calculated the average of the individual growth rates with no consideration for the reasonableness of the underlying data. Because Mr. Baudino failed to perform this essential step, his DCF analysis included individual growth rates that do not reflect investors' expectations. Therefore, his results are biased downward.

Q99. CAN YOU SHOW THE DOWNWARD BIAS IN MR. BAUDINO'S CONSTANT GROWTH ANALYSIS?

A99. Yes. For example, Mr. Baudino reports a First Call/IBES growth rate of 1.17% for Public Service Enterprise Group.[110] Combining this growth rate with his corresponding dividend yield of 3.85% results in a cost of equity estimate of 5.02%. Similarly, combining Exelon's First Call/IBES growth rate of 1.47% with its dividend yield of 3.74% produces an ROE estimate of 5.21%. These implied costs of equity do not sufficiently exceed yields on current and projected public utility

[109] The implied cost of equity estimates are calculated as the sum of the dividend yield (3.5%) and the respective growth rates (0.0%, 6.5%, and 14.0%).
[110] Exhibit RAB-5.

bonds. As a result, these illogical growth measures should have been removed from Mr. Baudino's constant growth DCF analysis.

B. Capital Asset Pricing Model

Q100. WHAT IS THE BIGGEST ISSUE YOU HAVE WITH MR. BAUDINO'S CAPM ANALYSIS?

A100. Mr. Baudino's CAPM results are simply so low they should be rejected outright. Results from his current market premium CAPM range from 7.25% to 7.51%; while results from his historic market premium model range from 5.80% to 7.18%. These outcomes are not legitimate ROE estimates.

Q101. CAN YOU IDENTIFY DEFECTS IN MR. BAUDINO'S CAPM METHODOLOGY?

A101. Yes. For instance, Mr. Baudino bases his risk-free rate on 5-year and 20-year Treasury securities. The other ROE witnesses in this case, including myself, rely more appropriately on the longer-term 30-year Treasury bond. As Dr. Woolridge states:

> The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.[111]

Mr. Walters also relies on the 30-year U.S. Treasury bond in his CAPM analysis, noting that "long-term Treasury bonds have an investment horizon similar to that of common stock."[112] Mr. Baudino's reliance on government debt with shorter maturities serves to unfairly deflate his CAPM results.

Next, Mr. Baudino attempts to develop a forecasted market return, which is a laudable goal. However, instead of simply relying on Value Line earnings forecasts, he introduces book value growth into the process. As I describe above,

[111] Woolridge LGE Direct at 60.
[112] Walters Direct at 55.

growth in EPS is the most influential driver of investors' long-term expectations. Adding book value growth only serves to depress his market return estimate, especially given that the earnings growth rate is 11.0% and the book value growth rate is 7.0%. If Mr. Baudino had left out the book value component, his market return projection would have been much more reasonable, at 11.81%.[113]

Q102. IS THERE ANOTHER SERIOUS PROBLEM ASSOCIATED WITH CAPM ANALYSIS DEVELOPED BY MR. BAUDINO?

A102. Yes, as I mentioned earlier in my response to Dr. Woolridge, the CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflect the expectations of actual investors in the market. Mr. Baudino has recognized that, "There is no real support for the proposition that an unchanging, mechanically applied historical risk premium is representative of current investor expectations and return requirements."[114]

Nevertheless, at least part of Mr. Baudino's application of the CAPM method was based entirely on *historical* – not projected – rates of return (Exhibit RAB-7). Because the backward-looking analyses of Mr. Baudino ignores the returns investors are currently requiring in the capital markets, the resulting CAPM estimates fall woefully short of investors' current required rate of return.

Q103. IS THERE ANY MERIT TO MR. BAUDINO'S ARGUMENT (P. 38) THAT YOUR ANALYSIS OF THE MARKET RATE OF RETURN SHOULD NOT HAVE BEEN LIMITED SOLELY TO THE DIVIDEND PAYING FIRMS IN THE S&P 500?

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[113] Exhibit RAB-6, page 2. Earnings growth of 11.0% plus the average dividend yield of 0.81% is 11.81%.

[114] *Direct Testimony and Exhibits of Richard A. Baudino*, Case No. 2012-00221 & Case No. 2012-00222, at p. 28 (October 2012).

A103. No. As Mr. Baudino recognized (p. 15-16), under the constant growth form of the DCF model, investors' required rate of return is computed as the sum of the dividend yield over the coming year plus investors' long-term growth expectations. Because the dividend yield is a key component in applying the DCF model, its usefulness is hampered for firms that do not pay common dividends. Accordingly, my DCF analysis of the market rate of return properly focused on the dividend paying firms included in the S&P 500.

Meanwhile, Mr. Baudino (p. 26) predicated his DCF analysis of the market rate of return on the companies followed by Value Line. Of the U.S. firms in Value Line, amounting to approximately 1,500 companies, approximately 500 do not pay common dividends. In other words, one-third of the companies that underpin Mr. Baudino's DCF analysis do not have the data necessary to implement this approach. Further, many of these firms are relatively small and lack a meaningful operating history. As a result, there is also greater uncertainty associated with estimating the future growth expectations that are central to the application of the DCF method. Taken together, these factors impugn the reliability of Mr. Baudino's market risk premium and confirm my decision to restrict the analysis to the established, dividend paying firms in the S&P 500.

Q104. DO THE ARGUMENTS ADVANCED BY MR. BAUDINO UNDERMINE THE NEED FOR A SIZE ADJUSTMENT AS PART OF THE CAPM AND ECAPM ANALYSES?

A104. No. Mr. Baudino simply observes that the average beta associated with the lower size deciles examined by *Duff & Phelps* is greater than the average his proxy group.[115] While I do not dispute the observation, it has no relevance whatsoever to the implications of *Duff & Phelps'* findings regarding the impact of firm size. The

[115] Baudino LGE Direct at 39.

fact that the average beta for smaller size deciles is greater than for 1.00 says nothing about the range of individual beta values underlying this average. Moreover, the size premiums are beta adjusted; meaning that the risk impact of beta values (whether higher or lower than Mr. Baudino's proxy group average) have been removed. While the size premiums reported by *Duff & Phelps* were not estimated on an industry-by-industry basis, this provides no basis to ignore this relationship in estimating the cost of equity for utilities. Utilities are included in the companies used by *Duff & Phelps* to quantify the size premium, and firm size has important practical implications with respect to the risks faced by investors in the utility industry. As *Duff & Phelps* concluded*:*

> Despite many criticisms of the size effect, it continues to be observed in data sources. Further, observation of the size effect is consistent with a modification of the pure CAPM. Studies have shown the limitations of beta as a sole measure of risk. The size premium is an empirically derived correction to the pure CAPM.[116]

C. Other ROE Issues

Q105. DOES MR. BAUDINO ADVANCE ANY CREDIBLE CRITICISM OF YOUR RISK PREMIUM APPROACH?

A105. No. Mr. Baudino's only observation is that the risk premium method is "imprecise."[117] Of course, this "criticism" applies equally to every model of investor behavior that is used to estimate required returns, including the DCF approach that formed the sole basis for Mr. Baudino's recommendation. The DCF method is only one theoretical approach to gain insight into the return investors require, which is unobservable. While the tautology of the DCF model boils this determination down to the familiar dividend yield and growth rate components, this masks the underlying complexities that accompany any attempt to distill every facet

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[116] *Duff & Phelps*, "2016 Valuation Handbook," (2016) at 4-27.
[117] Baudino LGE Direct at 40.

of investors' expectations into a single growth estimate. Mr. Baudino's claim that the DCF is "far more reliable and accurate" is unsubstantiated. While the DCF model is a recognized approach to estimating the cost of equity, it is not without shortcomings and does not otherwise eliminate the need to examine the results of other methods. As the Indiana Utility Regulatory Commission noted, for example:

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is . . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility – for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible, and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[118]

Q106. MR. BAUDINO ARGUES THAT THE USE OF FORECASTED INTEREST RATES IN THE ROE ESTIMATION PROCESS IS A PROBLEM BECAUSE THE PROJECTIONS MAY NOT MATERIALIZE (AT 31-34). DO YOU AGREE WITH THIS POSITION?

A106. No. As I stated in my Direct Testimony and earlier in this testimony, whether the projections of various services may be proven optimistic or pessimistic in hindsight, is irrelevant in assessing expected interest rates and how they might influence the Companies' allowed ROE.

Q107. HOW DO YOU RESPOND TO MR. BAUDINO'S DISCUSSION OF YOUR NON-UTILITY ANALYSIS?

A107. Mr. Baudino makes the statement that utilities "have protected markets, e.g., service territories, and may increase the prices they charge in the face of falling

[118] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).

demand or loss of customers."[119] Based on this, Mr. Baudino summarily concluded, "Obviously, the non-utility companies have higher overall risk structures." In fact, however, investors are quite aware that utilities are not guaranteed recovery of reasonable and necessary costs incurred to provide service and that there are many instances in which utilities are unable to increase rates to fully recoup reasonable and necessary costs, resulting in an inability to earn the allowed ROE – and potentially, even bankruptcy. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return.

Q108. DOES OBJECTIVE EVIDENCE SUPPORT MR. BAUDINO'S RISK ARGUMENTS?

A108. No. In fact, the objective risk measures specifically cited by Mr. Baudino as being relevant indicators of overall investment risks contradict his assertions. Similarly, Mr. Baudino testified that bond ratings reflect a detailed and comprehensive analysis of the key factors contributing to a firm's overall investment risk, concluding (p. 14), "Bond and credit ratings are tools that investors use to assess the risk comparability of firms."

Contradicting Mr. Baudino's unsupported assertion (p. 47) that the companies in my Non-Utility Group "have higher overall risk structures," my direct testimony noted that the average corporate credit rating for the Non-Utility Group of "A-" is <u>higher</u> than the "BBB+" average for the Utility Group and equal the ratings assigned to the Companies.[120] This assessment is confirmed by the review of beta values and other objective indicators of investment risk presented in Table 7 to my direct testimony, which consider the impact of competition and market

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[119] Baudino LGE Direct at 42.
[120] McKenzie LGE Direct at Table 7, p. 62.

share, demonstrated that, if anything, the Non-Utility Group could be considered less risky in the minds of investors than the common stocks of the proxy group of utilities.

Q109. MR. BAUDINO SAYS THAT AN ADJUSTMENT TO ACCOUNT FOR FLOTATION COSTS IS NOT NECESSARY SINCE "FLOTATION COSTS ARE ALREADY ACCOUNTED FOR IN CURRENT STOCK PRICES."[121] IS THIS A VALID ASSUMPTION?

A109. No. Mr. Baudino's position is akin to arguing that it is not necessary to reflect the utility's entire reasonable and necessary O&M expense in revenue requirements because such actions would be "accounted for" in the stock price. Flotation costs are legitimate expenses and unless a discreet adjustment is made to recognize them, they will not be recovered in the rate setting process.

IV. RESPONSE TO MR. WALTERS

Q110. HOW DID MR. WALTERS ARRIVE AT HIS RECOMMENDED COST OF EQUITY?

A110. Mr. Walters recommended an ROE of 9.35% based on his application of the constant growth and multi-stage forms of the DCF model, an application of the CAPM based on historical realized rates of return, and a risk premium approach based on allowed rates of return for utilities. Mr. Walters applied these methods to the same proxy groups of utilities identified in my Direct Testimony.

A. Discounted Cash Flow Model

Q111. HOW DID MR. WALTERS APPLY THE CONSTANT GROWTH DCF MODEL?

A111. Mr. Walters applied the constant growth DCF model using forward-looking estimates of EPS growth based on consensus forecasts of securities analysts, as well

[121] Baudino LGE Direct at 42.

as considering a sustainable, “br” growth rate. This is comparable to the method discussed in my testimony.

Q112. IS THERE AN OBVIOUS FLAW IN MR. WALTERS’ CONSTANT GROWTH DCF ANALYSIS?

A112. Yes. Mr. Walters failed to remove illogical values from his final constant growth DCF results. As I discuss in my Direct Testimony and in my rebuttal to Dr. Woolridge, when applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method. Removing the obvious low-end values from the DCF results presented on Mr. Walters’ Exhibit CCW-5 (Consolidated Edison at 6.46% and Public Service Enterprise Group at 5.60%) increases his constant growth DCF average by 33 basis points, from 9.20% to 9.53%.

Q113. IS THERE ANOTHER SHORTCOMING IN MR. WALTERS’ CONSTANT GROWTH DCF ANALYSIS?

A113. Yes. Mr. Walters elected to average all individual growth rates together, and then compute a single DCF estimate for each company. I discussed this issue previously in my response to Mr. Baudino and the same principle applies here. Because Mr. Walters failed to analyze individual DCF outcomes, his DCF analysis is biased downward and does not reflect investors’ expectations.

Q114. CAN YOU SHOW THE DOWNWARD BIAS IN MR. WALTERS’ CONSTANT GROWTH ANALYSIS?

A114. Yes. For example, Mr. Walters reports a Reuters growth rate of 2.02% for Consolidated Edison.[122] Combining this growth rate with his corresponding

[122] Exhibit CCW-4.

dividend yield of 3.81% results in a cost of equity estimate of 5.83%. This implied cost of equity does not sufficiently exceed yields on current and projected public utility bonds. As a result, this illogical growth measure should have been removed from Mr. Walters' constant growth DCF analysis.

Q115. DID MR. WALTERS LEAVE OUT A READILY AVAILABLE, WIDELY RESPECTED SOURCE OF ANALYSTS' GROWTH RATES?

A115. Yes, for no apparent reason, Mr. Walters did not include EPS growth rate estimates from Value Line in his analysis. He used Value Line as an underlying source for many of his calculations, such as to compute the annualized dividend and sustainable growth terms for his DCF models and the average beta for his CAPM studies. Value Line is readily available and is widely followed by investment professionals. Mr. Baudino noted that Value Line "is a widely used and respected source of investor information…"[123] It is a well-recognized source of expected growth rates and Mr. Walters' DCF analysis suffers because he did not consider them.

Q116. WHAT IS THE PROBLEM WITH MR. WALTERS' MULTI-STAGE GROWTH DCF ANALYSIS?

A116. This analysis should be completely rejected. There is no merit to Mr. Walters' claim that each company's growth would converge to the maximum sustainable growth rate for a utility company as proxied by consensus analyst's projected growth for the U.S. GDP of 4.25%. He incorrectly claims that GDP growth sets a "maximum sustainable long-term growth rate" for a utility.[124] As I discuss below, there is no link between Mr. Walters' GDP growth rate ceiling and the actual expectations of investors in the capital markets, which are the determining factor in any analysis of a fair ROE.

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[123] Baudino LGE Direct at 19.
[124] Walters LGE Direct at 36.

Q117. WHAT ARE THE PRIMARY MISCONCEPTIONS UNDERLYING MR. WALTERS' REFERENCE TO GDP GROWTH?

A117. Mr. Walters' use of long-term GDP growth as an upper bound to the DCF growth rate for companies in his proxy group is not justified. There are several reasons why GDP growth is not relevant in applying the DCF model:

- Practical application of the DCF model does not require a long-term growth estimate over a horizon of 25 years and beyond – it requires a growth estimate that matches investors' expectations.
- My evidence supports the conclusion that investors do not reference long-term GDP growth in evaluating expectations for individual common stocks, including those in the utility industry.
- The theoretical proposition that growth rates for all firms converge to overall growth in the economy over the very long horizon does not guide investors' views, and growth rates for utilities can and do exceed GDP growth.
- There is no evidence that investors' growth expectations for regulated utilities have begun to converge to that of the economy.

In short, there is no demonstrable evidence that investors look to GDP growth rates in the far distant future in assessing their expectations for utility common stocks. And while the theoretical assumptions underlying this method contemplate an infinite stream of cash flows, this is simply at odds with the practical circumstances in which real-world investors operate.

Q118. THE DCF MODEL IS BASED ON THE ASSUMPTION OF AN INFINITE STREAM OF CASH FLOWS. WHY WOULDN'T A TRANSITION TO GDP GROWTH MAKE SENSE?

A118. This view confuses the theory underlying the DCF model with the practicalities of its application in the real world. While the notion of long-term growth should presumably relate to the specific firm at issue, or at the very least to a particular industry, there are no long-term growth projections available for the companies in proxy group or for the electric utility industry as a whole. By applying the DCF model in a way that is inconsistent with the information that is available to investors and how they use it, the use of GDP growth places the theoretical assumptions of a financial model ahead of investor behavior. The only relevant growth rate is the growth rate used by investors. Investors do not have clarity to see far into the future, and there is little to no evidence to suggest that investors share the view that growth in GDP must be considered a limit on earnings growth over the long-term.

Q119. ARE THERE CIRCUMSTANCES THAT MIGHT SUPPORT THE USE OF A MULTI-STAGE DCF APPROACH?

A119. Yes. Reference to multiple growth rates may be reflective of investors' expectations for firms at the early stage of the corporate life cycle. Pioneering development firms may experience explosive earnings growth in initial years, which could reasonably be expected to moderate as the firm matures. Alternatively, a profound and definable shift in an industry's economics could also warrant consideration of multiple growth rates. For example, in deciding to adopt a two-step model for gas pipelines, FERC was concerned that IBES growth rates were "too influenced by the current position of the industry,"[125] noting:

> Northwest's expert witness testified that the short-term IBES figures were at historic high levels because the pipeline industry was recovering from the deterioration in earnings resulting from the collapse in oil prices and dramatic changes in regulatory framework.[126]

Similarly, in the 1990s when investors thought the electric utility was transitioning to non-regulated markets, two-stage models did fit investors' expectations. The first stage was based on expectations of growth rates under

[125] *Northwest Pipeline Co.*, Opinion No. 396-C at 17.
[126] *Id.*

regulation and the second stage would be more akin to non-utility growth rates. A number of experts presented two-stage models based on investors' expectations of a transition and a number of regulatory agencies found these models to be reasonable.

But expectations of widespread deregulation are a relic from the past and there is no evidence that the growth transition implied by a two-step model fits the expectations that investors currently build into electric utility stock prices. As Dr. Woolridge noted, "The economics of the public utility business indicate that the industry is in the steady-state or constant-growth state of a three-stage DCF."[127] Investors recognize that the electric utility industry is relatively stable and mature and their current view of does not anticipate a series of discrete, life cycle stages for the firms in the proxy group. As a result, there is no discernable transition that would support use of a multi-stage DCF approach.

Q120. ARE LONG-TERM GDP GROWTH RATES COMMONLY REFERENCED AS A DIRECT GUIDE TO FUTURE EXPECTATIONS FOR SPECIFIC FIRMS, SUCH AS ELECTRIC UTILITIES?

A120. No. Certainly investors consider broad secular trends in economic activity as one foundation for their expectations for a particular industry or firm. But the idea that investment advisory services view GDP growth as a direct guide to long-term expectations for a particular firm – much less every firm in an entire industry – is not borne out by evidence.

In contrast to this notion, in the financial media one observes many references to three-to-five year EPS growth forecasts for individual companies and very few references to long-term GDP forecasts. Long-term GDP growth rates are simply not discussed within the context of establishing investors' expectations for

[127] Woolridge LGE Direct at 45.

individual firms. For example, Value Line reports are routinely relied on as an important guide to apply the DCF model to utilities.[128] But despite Mr. Walters' suggestion that GDP has a fundamental role in shaping investors' growth estimates, Value Line does not even mention trends in GDP in its evaluation of the firms in the electric utility industry. Value Line's singleness of purpose is to inform investors of the pertinent factors that impact future expectations specific to each of the common stocks it covers. If the trajectory of GDP growth out to the year 2040 and beyond had direct relevance in investors' evaluation of utility common stocks, it would be logical to assume that Value Line or other securities analysts would give at least passing mention to this fact. But they do not.

Q121. HOW MUCH CONFIDENCE WOULD INVESTORS BE LIKELY TO PLACE ON LONG-TERM GDP PROJECTIONS?

A121. Very little. Investors understand the complexities and inherent inaccuracies involved in forecasting, and that such uncertainties are significantly compounded for a long-term time horizon. Consider the example of IHS Global Insight, which is perhaps the world's foremost econometric forecasting service. IHS Global Insight currently publishes GDP projections for the U.S. economy for the next thirty years, but for other important economic variables (*e.g.*, bond yields) their forecast simply holds projected values constant after a five-year horizon.

Q122. ARE THERE ALTERNATIVE METHODS OF ARRIVING AT AN EXPECTED GDP GROWTH RATE?

A122. Yes. Considering the potential for current long-term projections to be influenced by recent uncommonly low real growth in the U.S. economy, an alternative approach would be to combine a long-term historical average growth rate for GDP

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[128] As noted in *New Regulatory Finance*, "Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors." Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 71.

with a current projection of inflation. This method has been relied on by other regulators.[129] It is also the approach recognized by *Morningstar*:

> The growth rate in real Gross Domestic Product (GDP) for the period 1929 to 2012 was approximately 3.22 percent. Growth in real GDP (with only a few exceptions) has been reasonably stable over time; therefore, its historical performance is a good estimate of expected long-term (future) performance.[130]

Consistent with this approach the growth rate in real GDP would be equal to the average annual rate of change over the period 1929 through 2016, or 3.34%. With respect to expected inflation, the average long-term inflation forecast from IHS Global Insight, EIA, and the Social Security Administration is 2.36%. Combining an average real GDP growth rate of 3.34% with expected inflation of 2.36% results in an alternative projected GDP growth rate of 5.70%.

Q123. IS THERE EVIDENCE THAT LONG-TERM GDP GROWTH RATES UNDERSTATE INVESTORS' EXPECTATIONS FOR UTILITIES?

A123. Yes. Actual historical growth rates for individual firms in Mr. Walters' own proxy group refute the notion that long-term growth for utilities is constrained by GDP. For example, Value Line reports that Eversource Energy achieved earnings growth over the last 10 years of 9.5%. Meanwhile, CMS Energy had 10-year and 5-year EPS growth rates of 8.5%.[131] These values for Mr. Walters' own proxy firms indicate that utilities can and do achieve growth over extended periods far in excess of the GDP growth rate he suggests as a limit in the multi-stage DCF model.

Q124. DO EXPECTATIONS FOR THE UTILITY INDUSTRY SUPPORT A LONG-TERM TREND TOWARDS GDP GROWTH?

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[129] *See, e.g.*, Colorado Public Utilities Commission, Proceeding No. 14AL-039E, Decision No. R14-1298 (Oct. 28, 2014).
[130] Morningstar, "Ibbotson SBBI 2013 Valuation Yearbook (2013) at 52.
[131] The Value Line Investment Survey (February 17 & March 17, 2017).

A124. No. Growth rates for utilities are not expected to collapse beyond the next five years. At least in part, growth in the utility industry is created by additional infrastructure investment. Contrary to the assumption that growth trends will somehow mirror GDP, investors recognize that the utility industry has entered a cycle of significant capital spending on utility infrastructure. As the President of the Edison Electric Institute recently observed:

> The improved credit quality greatly supports the continued surge in capital expenditures, which rose by $7.2 billion, or 7.5 percent, to a new record high of $103.3 billion in 2015.[132]

The investment community understands that utilities are facing the prospect of a long-term commitment to infrastructure investment. For example, S&P has observed that:

> S&P Global Market Intelligence foresees continued high levels of capital spending by the industry, both on regulated and unregulated investment. Regulated capital spending includes spending on infrastructure replacement, new transmission and distribution facilities and lines, and regulated power plants, including new nuclear units currently under construction.[133]

Similarly, Deloitte published a report on utility capital expenditures and concluded the drivers behind continued strong spending included:

- The need to upgrade and reinforce electric and gas infrastructure due to age, increasingly severe weather, and cyber and physical threats
- The equally critical need to deploy information technology to boost the systems' efficiency, effectiveness, and resilience; accommodate the surge of new technologies and devices; and respond to customer demand for more flexible and customized products
- The need to address environmental concerns with an increasingly clean energy slate

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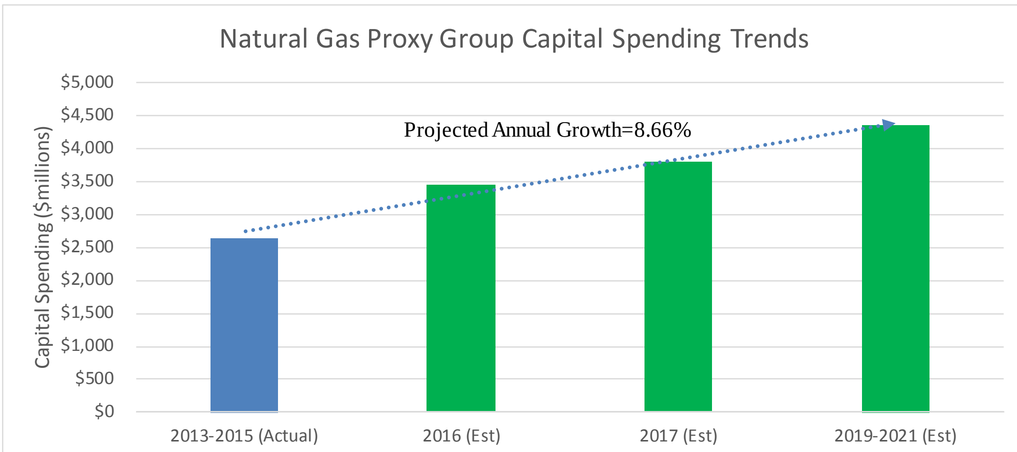
[132] Thomas R. Kuhn, "President's Letter," 2015 EEI Financial Review.
[133] Standard & Poor's Corporation, "Industry Surveys, Electric Utilities," (February 2016).

- The opportunity to take advantage of burgeoning supplies of domestic natural gas

> Overall, company projections indicate that capital spending will likely remain substantial, which is not surprising, since key drivers behind the spending continue.[134]

The following figure illustrates this trend for gas utilities.

FIGURE R-6



The Value Line Investment Survey (December 2, 2016).

Q125. ARE THERE INDICATIONS THAT HEIGHTENED CAPITAL EXPENDITURES WILL CONTINUE WELL BEYOND EEI'S 2019 HORIZON?

A125. Yes. A study published by the American Society of Civil Engineers ("ASCE") indicates that even with the recent upturn in utility capital spending, even more expenditures are coming:

> The needs to maintain and update existing electric energy infrastructure, to adopt new technologies, and to meet the demands of a growing population and evolving economy over the next 30

[134] Deloitte, "From growth to modernization, the changing capital focus of the US utility sector," (2016).

> years will impose significant requirements for new energy infrastructure investment.[135]

Based on a comparison of baseline capital expenditures for 2001-2010 and required investment levels needed to ensure reliability through 2040, the ASCE report concluded that an additional $731.8 billion in future investment needs would be required.

These well-documented expectations for a long-term cycle of capital investment in the electric utility industry imply higher – not lower – long-term growth, and again confirm that GDP growth estimates almost certainly understate investors' expectations for electric utilities.

Q126. DOES MR. WALTERS' OWN TESTIMONY SUPPORT THE PREMISE THAT THE GROWTH IN THE UTILITY INDUSTRY WILL EXCEED EXPECTED GROWTH IN GDP FOR THE FORESEEABLE FUTURE?

A126. Yes. Beginning on page 10 of his testimony, he cites several reports emphasizing the strong growth expected for the industry. A few excerpts are highlighted below:[136]

> - Capital expenditures throughout the U.S. power and gas sectors in calendar-2016 are projected to be at an all-time high;
> - The nation's largest electric and gas utilities are investing in infrastructure to comply with sweeping environmental regulations, implement new technologies, build new natural gas, solar and wind generation and upgrade aging transmission and distribution systems;
> - Moreover, their near-term capital spending forecasts continue to escalate;
> - In addition, replacement of mature gas distribution infrastructure has gained widespread momentum and is likely to continue at material levels for many years, considering state and federal mandates to address safety.

[135] American Society of Civil Engineers, *Failure to Act, The Economic Impact of Current Investment Trends in Electricity Infrastructure*, at 4 (Economic Development Research Group, Inc., 2011), *available at* http://www.asce.org/uploadedFiles/Infrastructure/Failure_to_Act/SCE41%20report_Final-lores.pdf.
[136] Walters Direct at 10.

Mr. Walters admits that "gas industry investment outlooks are expected to be considerably higher in the forecast (2016-2018), relative to the last 10-year historical period.[137] He adds "the capital investments for the electric utility industry are significantly higher than the capital investments for the gas industry but they follow the same trend over the historical and forecasted period."[138]

Q127. DID THE FOUNDER OF THE DCF APPROACH SUPPORT THE USE OF A GENERIC LONG-TERM GROWTH RATE, SUCH AS THE GDP GROWTH UNDER THE MR. WALTERS' MULTI-STAGE APPROACH?

A127. No. Professor Myron J. Gordon, who originated the DCF approach, concluded that reference to a generic long-term growth rate, such as Mr. Walters advocates, was unsupported.[139] More specifically, Dr. Gordon concluded that any assumption of a single time horizon for a transition to a generic long-term growth rate was highly questionable and failed to reduce error in DCF estimates. Instead, Dr. Gordon specifically recognized that, "it is the growth that investors expect that should be used" in applying the DCF model, and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[140]

Similarly, a recent study reported in the *Journal of Investing* determined that there is no correlation between stock market returns or earnings growth and GDP, suggesting that investors' expectations built into observable share prices are driven by valuation measures, and not expected economic growth.[141]

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[137] *Id.* at 11.
[138] *Id.* at 11.
[139] Myron J. Gordon, "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* (1974) at 100-01.
[140] *Id.* at 89.
[141] Joachim Klement, "What's Growth Got to Do with It? Equity Returns and Economic Growth," *Journal of Investing*, Vol. 24, No. 2 (Summer 2015): 74:78.

Q128. HAVE OTHER REGULATORS RECOGNIZED THAT GDP GROWTH RATES RESULT IN COST OF EQUITY ESTIMATES THAT FAIL TO REFLECT INVESTORS' EXPECTATIONS FOR UTILITIES?

A128. Yes. In Opinion No. 531 (issued June 19, 2014), FERC concluded that a 9.39% midpoint produced by a multi-stage DCF model predicated on GDP growth is insufficient to meet regulatory standards under *Hope* and *Bluefield.*[142] FERC determined that a cost of equity of this magnitude "does not represent a just and reasonable outcome" or "appropriately represent the utilities' risks."[143] In particular, FERC concluded that historically anomalous capital market conditions are leading to unrepresentative financial inputs to the DCF formula, which in turn results in a cost of equity "that does not satisfy the requirements of *Hope* and *Bluefield*."[144]

In order to evaluate a fair and reasonable point-estimate ROE, FERC endorsed reliance on the same risk premium, CAPM, and expected earnings approaches presented in my testimony in this case.[145] In addition, FERC stressed the relevance of ROEs allowed by state regulatory commissions in its evaluation of a fair ROE from within the zone of reasonableness.[146] More recently, FERC affirmed these findings in Opinion No. 551.[147]

Q129. PLEASE SUMMARIZE YOUR OBJECTION TO MR. WALTERS' USE OF GDP GROWTH RATES IN HIS MULTI-STAGE GROWTH DCF ANALYSIS?

A129. Mr. Walters presents no meaningful information to suggest that investors share his view that growth in GDP must be considered "the highest sustainable long-term

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[142] Opinion No. 531, 147 FERC ¶ 61,234 at P 142.
[143] *Id.* at P 144.
[144] *Id.* at P 142.
[145] *Id.* at P 146.
[146] Opinion No. 531, 147 FERC ¶ 61,234 at P 148-149. FERC ultimately concluded that an ROE of 10.57% was just and reasonable.
[147] Opinion No. 551. FERC ultimately concluded that an ROE of 10.32% was just and reasonable.

growth rate of a utility."[148] The industry-wide historical comparisons of utility sales growth and GDP cited by Mr. Walters may be factually correct, but they do not address what Mr. Walters identified as the fundamental requirement in estimating growth – the future expectations of investors. In fact, Mr. Walters specifically noted the pitfalls associated with historical data in assessing investors' expectations of growth.

Mr. Walters suggests that it would be illogical for investors to expect long-term growth for a utility that exceeds the rate of growth of the economy. Based on this subjective assertion, he assumed that each company's growth rate would begin to converge to that of the economy as a whole after 5 years, and then extended his analysis for an additional 195 years. While few investors are likely to consider Mr. Walters' projected cash flows in the year 2217 to be within their foreseeable horizon, it is entirely logical for investors to recognize the potential for certain companies to grow faster than the overall economy.

Q130. ARE THERE COMPUTATIONAL ERRORS THAT ALSO BIAS MR. WALTERS' MULTI-STAGE DCF COST OF EQUITY ESTIMATES DOWNWARD?

A130. Yes. As noted above, under his multi-stage DCF approach Mr. Walters predicted the cash flows that would accrue to investors over the next 200 years. To arrive at his estimated cost of equity, Mr. Walters used the internal rate of return ("IRR") function available in Microsoft's Excel spreadsheet program to determine the discount rate (*i.e.*, investors' required rate of return) that would equate these cash flows with the current market price of the stock.[149] This IRR calculation, however, assumes that annual cash flows are received at the end of each year, which is

[148] *Id.*
[149] Walters workpaper: CCW Confidential WP 10.xlsx.

inconsistent with the periodic dividend payments that investors receive over the course of the year and results in a downward bias in the implied cost of equity.

B. Capital Asset Pricing Model

Q131. WHAT ARE THE WEAKNESSES IN MR. WALTERS' CAPM STUDIES?

A131. Mr. Walters' CAPM analysis has several shortcomings. Like the other ROE Witnesses, it is based almost exclusively on historical data, even though the analysis should be forward-looking. He fails to correct for an observed bias in the CAPM result. Finally, his analysis ignores the impact of company size on expected returns.

Q132. WHAT IS THE PRIMARY DIFFERENCE BETWEEN MR. WALTERS' SO-CALLED "FORWARD-LOOKING" CAPM ANALYSIS AND THE APPROACH DESCRIBED IN YOUR DIRECT TESTIMONY?

A132. As Mr. Walters observed, the appropriate "R_m" to use in applying the CAPM is the "[e]xpected return for the market portfolio."[150] The fundamental difference between my approach and that of Mr. Walters is that, while my analysis actually looked to the future return expectations of investors in the capital markets, Mr. Walters' "forward-looking" CAPM was actually based almost entirely on <u>historical</u> data. As Mr. Walters explained:

> I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term <u>historical</u> arithmetic average real return on the market.[151] [emphasis added]

In other words, the relatively small portion of Mr. Walters' "forward-looking" market return constituting inflation was based on projected data, but the actual return on the market itself was <u>completely backward looking</u>. Thus, Mr. Walters essentially presented two variants of a CAPM using historical data. Neither

[150] Walters Direct at 54.
[151] *Id.* at 56.

one of these approaches is consistent with the assumptions of the CAPM because as noted above, the CAPM seeks to determine the expected return, and is predicated on the forward-looking expectations of investors. As discussed earlier in response to Dr. Woolridge, Mr. Walters' use of historical returns in the CAPM is inconsistent with the underlying presumptions of the model.

Q133. WHAT ABOUT MR. WALTERS' CRITICISM THAT YOUR FORWARD-LOOKING ESTIMATE OF THE MARKET RATE OF RETURN IS NOT REASONABLE?[152]

A133. As noted earlier, the use of forward-looking expectations in estimating the market risk premium is well accepted in the financial literature and has been recognized by other regulators. Mr. Walters' criticism of my forward-looking CAPM approach seems to hinge on the fact that this method produces an equity risk premium for the S&P 500 that is higher than the historical benchmarks he cites. But estimating investors' required rate of return by reference to current, forward-looking data, as I have done, is entirely consistent with the theory underlying the CAPM methodology. As noted earlier, the CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of required rates of return, the CAPM is best applied using data that reflects the expectations of actual investors in the market. Rather than look backwards to a risk premium based largely on historical data, as Mr. Walters advocates, my analysis appropriately focused on the expectations of actual investors in today's capital markets.

All quantitative methods used to estimate the cost of equity have their own strengths and weakness. Mr. Walters does not suggest that the CAPM model is "wrong" to focus on forward-looking projections instead of backward, historical

[152] *Id.* at 70.

results, nor does he claim that looking to the future, as I have done, is a misapplication of the CAPM. Instead, Mr. Walters simply believes that the result of applying the CAPM in a manner that is consistent with the underlying assumptions produces a result that he views as being too high.

Q134. HAVE OTHER REGULATORS RELIED ON A FORWARD-LOOKING DCF APPROACH SIMILAR TO THE ONE PRESENTED IN YOUR DIRECT TESTIMONY AS A MEANS OF ESTIMATING THE MARKET COST OF EQUITY?

A134. Yes. I based my CAPM approach on the methods used by the Staff at the Illinois Commerce Commission, whose witnesses have routinely relied on a forward-looking market rate of return estimate to apply the CAPM. For example, Illinois Staff witness Rochelle Langfeldt employed an expected market return based on an analysis analogous to the approach described in my direct testimony:

> Q. How was the expected rate of return on the market portfolio estimated?
>
> A. The expected rate of return on the market was estimated by conducting a DCF analysis on the firms composing the S&P 500 Index ("S&P 500"). … Firms not paying a dividend as of June 28, 2001, or for which neither Zacks nor IBES growth rates were available were eliminated from the analysis. The resulting company-specific estimates of the expected rate of return on common equity were then weighted using market value data from Salomon Smith Barney, Performance and Weights of the S&P 500: Second Quarter 2001. The estimated weighted averaged expected rate of return for the remaining 365 firms composing 78.31% of the market capitalization of the S&P 500 equals 15.31%.[153]

Moreover, the market cost of equity relied on in my analysis represents a weighted average expected return for the dividend paying firms in the S&P 500. Growth expectations for some firms fall below expected trends GDP, while

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[153] Direct Testimony of Rochelle Langfeldt, Illinois Commerce Commission Docket No. 01-0423 at 23-24 (2001).

projections for other firms are considerably more optimistic. Similarly, the composition of the S&P 500 is not static and growth rates for one company may moderate over time, while for others they may increase. On balance, however, the growth rates used in my study are representative of the consensus expectations for the dividend paying firms in the S&P 500 Index as a whole. This contradicts Mr. Walters' position that investors' growth expectations should be constrained by forecasted GDP growth when estimating the market cost of equity.[154]

Q135. DID MR. WALTERS FAIL TO CONSIDER OTHER IMPORTANT FACTORS IN APPLYING THE CAPM?

A135. Yes. Mr. Walters failed to reflect the size adjustment in his CAPM application. According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, *Morningstar* has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity. Accordingly, Mr. Walters should have incorporated an adjustment to recognize the impact of size distinctions between his proxy companies, as measured by the average market capitalization.

Q136. IS THERE ANY MERIT TO MR. WALTERS' CONTENTION THAT A SIZE ADJUSTMENT SHOULD NOT BE APPLIED TO UTILITIES?[155]

A136. No. First, Mr. Walters implies that I am proposing to apply a general size risk premium in arriving at a fair ROE for the Companies; but this is not correct. Rather,

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[154] Walters Direct at 41.
[155] *Id.* at 71.

this adjustment merely corrects for an observed inability of the CAPM to fully reflect the impact of size distinctions by market capitalization that the beta value does not otherwise capture, but which is acknowledged by empirical research. My consideration of the impact of firm size does not adjust for KU's or LG&E's size relative to the proxy group; nor is it applied to the results of the DCF, risk premium, or expected earnings approaches. Rather, it is specifically tied to the CAPM because empirical research indicates that beta does not capture an increment of risk related to firm size.

Mr. Walters' observation that the "size adjustment recommended by Mr. McKenzie reflects companies that have beta estimates in excess of 1.00" says nothing at all about the relevance of a size adjustment.[156] Of course, there are any number of specific factors that distinguish a utility's risks from other firms in the non-regulated sector, just as there are important distinctions between the circumstances faced by airlines and drug manufacturers. But under the assumptions of modern capital market theory on which the CAPM rests, these considerations are reduced to a single risk measure – beta – which captures stock price volatility relative to the market. Within the CAPM paradigm, the degree of regulation, the nature of competition in the industry, the competence of management, and every other firm-specific consideration is boiled down to a single question; namely, how much does the stock's price fluctuate in relation to the market as a whole? Beta is the measure of that variability, and research demonstrates that beta does not fully account for the impact of firm size.

As noted earlier, the fact that the size premiums reported by *Duff & Phelps* were not estimated on an industry-by-industry basis provides no basis to ignore this relationship in estimating the cost of equity for utilities. A study reported in *Public*

[156] *Id.* at 71-72.

Utilities Fortnightly noted that the betas of small companies do not fully account for the higher realized rates of return associated with small company stocks:

> The smaller deciles show returns not fully explainable by the CAPM. The difference in risk premium (realized versus CAPM) grows larger as one moves from the largest companies in decile 1 to the smallest in decile 10. The difference is especially pronounced for deciles 9 and 10, which contain the smallest companies. [157]

The study went on to conclude that a publicly traded utility with a market capitalization of $1.0 billion would require a small company premium of approximately 130 basis points above the rate of return for larger firms.[158]

Mr. Walters further confuses the size adjustment required by the CAPM with aspects of the "build-up model" described in a Duff & Phelps publication.[159] The build-up model and the CAPM are not synonymous and in fact are distinct methods for estimating the cost of equity. The "industry risk premium adjustment" cited by Mr. Walters in the context of the build-up method is *in lieu of* the more precise beta risk measure for each firm in the proxy group that is employed in the CAPM. Mr. Walters is misleading by wrongly suggesting that the "industry risk premium factor" and the beta measure used in the CAPM are somehow additive. In fact, they are mutually exclusive adjustments pertaining to entirely different analytical approaches, and there is no basis for Mr. Walters' contention that I "cherry-picked" the size adjustment.[160]

Q137. MR. WALTERS REJECTS YOUR USE OF THE ECAPM BECAUSE HE SAYS IT AMOUNTS TO DOUBLE COUNTING WHEN USED WITH VALUE LINE ADJUSTED BETAS.[161] WHAT IS YOUR RESPONSE?

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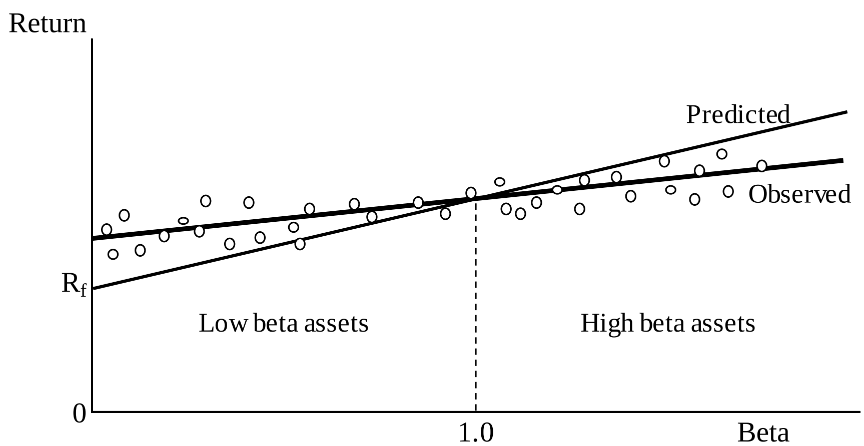
[157] Michael Annin, "Equity and the Small-Stock Effect", *Public Utilities Fortnightly* (Oct. 15, 1995) at 43.
[158] This compares with the size adjustments incorporated in my application of the CAPM and ECAPM, which ranged from -36 basis points to 149 basis points (Exhibit Nos. 7-8).
[159] Walters Direct at 71, 73.
[160] *Id.* at 71.
[161] Walters Direct at 76.

A137. As I stated in my Direct Testimony,[162] the ECAPM is simply a variant of the traditional CAPM approach that is designed to correct for an observed bias in the CAPM result. The modification reflected in the ECAPM is distinct from the Value Line adjustment of estimated betas for the demonstrated tendency to regress toward the mean. The Value Line adjustment is intended to make betas estimated based on historical returns better estimates of forward-looking betas.

In contrast, the ECAPM reflects a refinement to adjust for a systematic tendency of low beta portfolios to over-earn and high beta portfolios to under-earn relative to the predictions of the CAPM capital market line. This is illustrated graphically in the figure below:

FIGURE R7
CAPM – PREDICTED VS. OBSERVED RETURNS



The ECAPM reflects a refinement to adjust for a systematic tendency of low beta portfolios to over-earn and high beta portfolios to under-earn relative to the predictions of the CAPM capital market line. In other words, even if a firm's beta value were estimated with perfect precision, the CAPM would still understate the return for low-beta stocks and overstate the return for high-beta stocks. The

[162] McKenzie LGE Direct at 46-48.

ECAPM and the use of adjusted betas represent two separate and distinct issues in estimating returns, and both are useful for improving the traditional CAPM results.

In contrast to Mr. Walters' dismissal of this approach, the results of the ECAPM have been relied on by other regulators. For example, Staff witness Julie McKenna of the Maryland Public Service Commission noted that "the ECAPM model adjusts for the tendency of the CAPM model to underestimate returns for low Beta stocks," and concluded that, "I believe under current economic conditions that the ECAPM gives a more realistic measure of the ROE than the CAPM model does."[163] The Regulatory Commission of Alaska has also relied on the ECAPM approach, noting that:

> Tesoro averaged the results it obtained from CAPM and ECAPM while at the same time providing empirical testimony that the ECAPM results are more accurate then [sic] traditional CAPM results. The reasonable investor would be aware of these empirical results. Therefore, we adjust Tesoro's recommendation to reflect only the ECAPM result.[164]

C. Utility Risk Premium

Q138. DO THE RESULTS OF MR. WALTERS' RISK PREMIUM APPROACH BASED ON AUTHORIZED RETURNS PROVIDE A RELIABLE GUIDE TO A FAIR ROE FOR THE COMPANIES?

A138. No. Mr. Walters subjectively chose to truncate the data available to apply his risk premium approach by ignoring all observations prior to 1986. Mr. Walters explained that this period was selected "because public utility stocks consistently traded at a premium to book value during that period,"[165] but such manipulation of this data runs counter to the assumptions underlying the study of historical risk premiums. Ibbotson Associates noted the pitfalls of such a subjective approach:

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[163] *Direct Testimony and Exhibits of Julie McKenna*, Maryland PSC Case No. 9299 (Oct. 12, 2012) at page 9.
[164] Regulatory Commission of Alaska, Order No. P-97-004(151) at 145 (Nov. 27, 2002).
[165] Walters Direct at 47.

> Some analysts estimate the expected risk premium using a shorter, more recent time period on the basis that recent events are more likely to be repeated in the near future … This view is suspect …[166]

By choosing a truncated time period for his risk premium study, Mr. Walters unnecessarily introduces a subjective bias that taints his analysis and artificially lowers his results.

Q139. WHAT OTHER FLAWS ARE ASSOCIATED WITH MR. WALTERS' RISK PREMIUM APPLICATION?

A139. Mr. Walters failed to incorporate the inverse relationship between interest rates and equity risk premiums in his analysis of historical authorized rates of return. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater. This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. As summarized in *New Regulatory Finance*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carelton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[167]

New Regulatory Finance noted that, taken together, studies in the financial literature imply that a 100 basis point change in bond yields would imply a 50 basis point increase in the equity risk premium.[168]

As shown on Mr. Walters' Exhibits CCW-12 and CCW-13, current interest rates are significantly less than those prevailing in the late 1980s and early 1990s. Given that interest rates are currently lower than the average over his study period,

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[166] Ibbotson Associates, *2005 Yearbook, Valuation Edition* at 80.
[167] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 128.
[168] *Id.* at 129.

current equity risk premiums should be relatively higher, which Mr. Walters' analysis entirely ignores.

Q140. WHAT COST OF EQUITY ESTIMATE IS INDICATED IF MR. WALTERS' RISK PREMIUM APPROACH IS CORRECTED TO ACCOUNT FOR THIS FACTOR?

A140. I began with the data from Mr. Walters' two risk premium Exhibits CCW-12 and CCW-13. The only adjustment I made to this data was to account for the inverse relationship between interest rates and risk premiums. Since rates are now (historically) low, an upward adjustment to the base risk premium is critical. As shown on Rebuttal Exhibit No. 16, adjusting Mr. Walters' risk premium analysis to account for this inverse relationship results in a current cost of equity estimate for the Companies of 10.05% using Treasury yields (page 1), or 9.87% based on public utility bond yields (page 3).

D. Other ROE Issues

Q141. MR. WALTERS ACCUSES YOU OF "MANIPULATING" YOUR DCF RESULTS BECAUSE YOU REMOVED SEVERAL LOW-END VALUES FROM YOUR RESULTS AND ONLY REMOVED ONE HIGH-END ESTIMATE.[169] IS THIS A VALID CRITICISM?

A141. No. As discussed above in response to Dr. Woolridge, low-end values were evaluated against the observable returns available from long-term bonds. But the fact that there are numerous results that fail this test of reasonableness says nothing about the validity of estimates at the upper end of the range of results, and there is no basis to discard an equal number of values from the top of the range. In my Exhibit No. 5, I retained an upper end cost of equity estimate of 13.2%, but I also

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[169] Walters Direct at 69.

kept low-end estimates in the 7.0% range which are assuredly far below investors' required rate of return.

Q142. MR. WALTERS SUGGESTS THAT USING THE MEDIAN WOULD BE A BETTER APPROACH THAN REMOVING OUTLIERS IN DEALING WITH EXTREME DCF RESULTS.[170] DO YOU AGREE?

A142. No. Similar to my earlier discussion of Mr. Walters' DCF averaging technique, I believe that each ROE result represents a stand-alone estimate of investors' future expectations, and each value should be evaluated on its own merits. The fact that a median of several outcomes might produce a DCF estimate that could be considered reasonable does not absolve the need to evaluate each underlying return separately. Without considering the underlying data, and including ROE estimates that do not reflect investor expectations, Mr. Walters' median approach biases his results downward.

Q143. MR. WALTERS CONTENDS THAT THE EXPECTED EARNINGS ANALYSIS YOU USED IS NOT A REASONABLE METHOD FOR ESTIMATING A FAIR ROE FOR KU AND LG&E.[171] DO YOU AGREE?

A143. No. I provided support for the expected earnings method in my earlier rebuttal of Dr. Woolridge and in my Direct Testimony. The appeal of the expected earnings approach is that it does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

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[170] *Id.* at 69.
[171] *Id.* at 84.

Q144. DO YOU AGREE WITH MR. WALTERS THAT A METHODOLOGY HAS TO DEPEND ON MARKET DATA TO BE USEFUL IN EVALUATING INVESTORS' REQUIRED RETURN?[172]

A144. No. Mr. Walters wrongly contends that because the expected earnings approach is based on accounting data and not market data, it should be rejected. While I agree that market-based models are certainly important tools in estimating investors' required rate of return, in my opinion, this in no way invalidates the usefulness of the expected earnings approach. In fact, this is one of its advantages. As discussed earlier, a very simple, conceptual principle is that when evaluating two investments of comparable risk, investors will choose the alternative with the higher expected return. If the Companies are only allowed the opportunity to earn a 9.35% return on the book value of their equity investments, as recommended by Mr. Walters, while other utilities are expected to earn an average of 11.2%,[173] the implications are clear – the Companies' investors will be denied the ability to earn a return commensurate with other opportunities of comparable risk.

Q145. MR. WALTERS FAULTS YOUR NON-UTILITY DCF APPROACH BECAUSE, ACCORDING TO HIM, THE NON-UTILITY GROUP IS "MUCH RISKIER" THAN THE UTILITY INDUSTRY.[174] HOW DO YOU RESPOND?

A145. In my Direct Testimony, I compared risk indicators for the non-utility group to my proxy group and to the Companies. This comparison is reproduced below.

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[172] *Id.* at 84.
[173] The average expected return on book equity for 2020-22 calculated for Mr. Walters' proxy group, as shown on Rebuttal Exhibit No. 14.
[174] Walters Direct at 85.

TABLE R-4
COMPARISON OF RISK INDICATORS

	Credit Rating		Value Line		
	S&P	Moody's	Safety Rank	Financial Strength	Beta
Non-Utility Group	A-	A3	1	A+	0.69
Utility Group	BBB+	Baa1	2	A	0.70
KU/LG&E	A-	A3	2	B++	0.70

As I concluded in my Direct Testimony, based on these parameters, investors would likely conclude that the overall investment risks for the Utility Group and KU are greater than those of the firms in the Non-Utility Group. Mr. Walters' suggestion to the contrary is misleading and should be ignored.

Q146. DO YOU AGREE WITH MR. WALTERS' FLOTATION COST DISCUSSION?

A146. No. Mr. Walters rejects a flotation cost adjustment because he claims it "is not based on known and measurable LG&E costs."[175] Mr. Walters seems to agree that flotation costs can be included in the cost of equity analysis as a part of the cost of raising capital, but he argues that such an adjustment should be rejected in this case. KU and LG&E has been and will continue to invest significant amounts of equity capital to serve the public. The equity capital necessary to support this investment is supplied by proceeds from past stock issues and through retained earnings. The earnings base of this equity is permanently reduced by the amount of past flotation costs. Without a flotation adjustment, these legitimate costs of providing utility service will be excluded for ratemaking purposes and will further undercut the Companies' ability to earn their authorized ROE.

[175] *Id.* at 66.

V. RESPONSE TO MR. TILLMAN

Q147. DID MR. TILLMAN CONDUCT AN INDEPENDENT EVALUATION OF A FAIR ROE FOR THE COMPANIES?

A147. No. Mr. Tillman did not conduct any analyses of the cost of equity. His testimony was limited to a presentation of selected data concerning previously authorized ROEs. Based on this limited review, Mr. Tillman expressed his concern that a 10.23% ROE for the Companies is "excessive."[176]

Q148. DO YOU AGREE WITH MR. TILLMAN THAT ALLOWED ROES PROVIDE ONE BENCHMARK WORTHY OF CONSIDERATION IN THE COMMISSION'S EVALUATION?

A148. Yes, I do. Importantly, however, such comparisons of allowed ROEs are only one consideration. While this data can be useful in the KPSC's deliberations, it is not a substitute for the detailed analyses presented in my direct testimony.

Q149. DOES THE DATA PRESENTED BY MR. TILLMAN CONFIRM YOUR CONCLUSION THAT DR. WOOLRIDGE'S, MR. BAUDINO'S, AND MR. WALTERS' RECOMMENDATIONS ARE TOO LOW?

A149. Yes. Mr. Tillman cites an average allowed ROE for vertically integrated utilities of 9.82% for 2014 through the present,[177] which confirms my earlier conclusion that the 8.75%, 9.00%, and 9.35% ROE recommendations of the ROE witnesses fall well below average returns authorized for other utilities, and are insufficient to meet the requirements of regulatory standards.

Q150. DO YOU AGREE WITH THE INFERENCE THAT MR. TILLMAN DRAWS FROM HIS REVIEW OF ALLOWED ROES?

A150. No. There is no basis for Mr. Tillman to suggest that average authorized ROEs are somehow skewed upwards because of specific awards in certain states. Mr.

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[176] Tillman LGE Direct at 8.
[177] *Id.* at 14.

Tillman points to ROEs above 10% awarded in Michigan, but he made no effort to examine results at the low-end of the range. For example, the 9.30% ROE result for Kansas City Power and Light's Kansas operations was, according to RRA, part of a settlement that "did not address rate-of-return issues."[178] In short, while a review of historical authorized ROEs can provide a general benchmark, it is not a substitute for a thorough analysis of the cost of capital, such as that contained in my direct testimony and supporting the Companies' 10.23% requested ROE. As discussed in detail earlier, data concerning historical allowed ROEs reported by RRA can be informative, but do not substitute for a comprehensive application of primary methods.

Q151. FROM YOUR POSITION AS A REGULATORY FINANCIAL ANALYST, WHAT DO YOU MAKE OF MR. TILLMAN'S ADMONITION (PP. 7-8) TO CONSIDER CUSTOMER IMPACTS WHEN ESTABLISHING A FAIR ROE?

A151. First, it is important to note that the determination of the ROE is made by investors in the capital markets, and is not predicated on any notion of costs or savings to customers. The U.S. Supreme Court's regulatory standards embodied in the *Hope* and *Bluefield* decisions represent a balance between the interests of customers and investors, by setting forth the guidelines as to a fair ROE. Meanwhile, Mr. Tillman wrongly suggests that a lower ROE is *per se* in customers' benefit. This is not the case. While a downward-biased ROE may provide the illusion of customer "savings" in the form of a lower revenue requirement in the short-term, the long-term impact of an inadequate ROE can be injurious to customers and the Kentucky economy.

[178] Regulatory Research Associates Regulatory Focus, *Major Rate Case Decisions-Calendar 2015*, January 14, 2016, pp. 5 and 9.

As discussed earlier, there is a very real connection between the ROE and the availability of capital, and Mr. Tillman ignores the negative impact that an inadequate ROE would have on investment. The ROE is the primary signal to investors, not only with respect to attracting new capital investment, but also in supporting existing utility operations. If the utility is unable to offer a competitive ROE, existing shareholders will suffer a capital loss as investors take advantage of other, more favorable opportunities, and the utility's stock price would fall. Moreover, as investors' confidence is undermined, the ability of utilities to access equity capital markets and expand investment will suffer. While the Companies would undoubtedly continue to meet their service obligations to customers, a downward-biased ROE would send an unmistakable signal to the investment community as they consider whether to commit capital in Kentucky, and at what cost.

Q152. DO YOU AGREE WITH MR. TILLMAN'S ASSESSMENT REGARDING THE IMPACT OF CONSTRUCTION WORK IN PROGRESS ("CWIP")?

A152. No. While Mr. Tillman attempts to distinguish the risks of the Companies based on the opportunity to include CWIP in rate base, this is hardly novel or unique to the Companies and has been widely utilized since the 1970s to address the impact of construction costs on utilities' financial integrity.

Q153. WHAT IS CWIP?

A153. CWIP consists of investment in facilities built to meet service obligations that are not yet physically providing service. For an electric utility, CWIP can be sizeable as a result of the capital intensity of utility infrastructure investment and the extended construction periods involved with these facilities. During the construction phase, the utility must pay capital carrying costs (interest, dividends, etc.) on the investment in new facilities. These capital carrying costs are typically accrued for future recovery in the form of Allowance for Funds Used During

Construction ("AFUDC"), which is included in rate base at the time the facilities are placed in service. Alternatively, regulators may allow CWIP to be included in rate base and thus permit the utility an opportunity to recover these capital costs through current rates.

Q154. WHAT IS THE FINANCIAL IMPACT OF CWIP?

A154. If CWIP is included in rate base, the utility's revenue requirements are increased by the capital costs associated with the new construction. As a result, since customers pay the capital carrying costs of CWIP in current rates, capitalized AFUDC is not added to plant cost. From the utility's standpoint, current cash flow is higher than it would have been otherwise. As a result, including CWIP in rate base improves a utility's cash flow and increases revenue requirements during the construction phase; however, this increase is offset in the future by the lower rate base that results from eliminating capitalized AFUDC.

While the level of a utility's earnings does not differ dramatically depending on whether or not CWIP is included in rate base, the cash flow implications can be significant, especially in the case of a large construction program. To finance the costs of construction, utilities such as the Companies must obtain financing in the form of common equity or long-term debt. If CWIP is not included in rate base, no cash is generated from current rates to meet the interest and dividend payments associated with these securities, which in turn must be financed.

The uncertainties that investors associate with cost deferrals and a deterioration in earnings quality are significant and many of the key indicators relied on by securities analysts and bond rating agencies focus on measures of cash flow. As a result, the greater risk associated with higher levels of non-cash earnings (*i.e.*, AFUDC) would ultimately be reflected in higher rates of return required by investors. Investors recognize that including CWIP in rate base is an important tool that supports the utility's financial integrity and attenuates some of the financial risks associated with new infrastructure investment.

Q155. IS THERE ANY MERIT TO MR. TILLMAN'S CONTENTION (P. 11) THAT INCLUDING CWIP IN RATE BASE "SHIFTS RISKS ONTO RATEPAYERS?"

A155. No. Including CWIP in rate base will ease the financial pressure associated with the Companies' capital projects by improving cash flow and providing greater regulatory certainty. While instrumental in supporting financial integrity and ability to attract capital, including CWIP will not have a measurable impact on the overall investment risks of the Companies or investors' required rate of return. Including CWIP in rate base changes only the timing of cost recovery for projects included in CWIP. Accordingly, CWIP does not shift risks to ratepayers, as alleged by Mr. Tillman.

Q156. HAVE OTHER REGULATORS RECOGNIZED THE POTENTIAL BENEFITS ASSOCIATED WITH INCLUDING CWIP IN RATE BASE?

A156. Yes. Investors recognize that it is not uncommon for regulators to include CWIP in rate base when establishing rates. A study by the Edison Electric Institute observed that:

> The inclusion of CWIP in rate base improves cash flow and reduces future rate shocks. This practice also reduces the losses that a utility experiences making large plant additions under historical test year rates. Monitoring by the Edison Electric Institute has found that states that have recently allowed the inclusion of CWIP in rate base include CO, FL, GA, IN, KS, KY, LA, MI, MO, NC, NM, NV, SD, TN, VA, and WV.[179]

Accordingly, the cost of equity estimates developed for the proxy companies already reflects any impact associated with the opportunity to earn a return on CWIP. FERC has also recognized that including CWIP balances the

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[179] Edison Electric Institute, *Forward Test Years for US Electric Utilities* (August 2010).

interest of investors and customers, and the Commission has routinely allowed electric utilities to include CWIP in rate base.[180] FERC noted in *Order No. 679* that including CWIP in rate base provides "up-front regulatory certainty, rate stability and improved cash flow" that encourage investment by "easing the financial pressures" associated with construction programs.[181]

Q157. IS MR. TILLMAN'S POSITION WITH RESPECT TO CWIP CONSISTENT WITH ESTABLISHED PRECEDENT IN KENTUCKY?

A157. No. Mr. Tillman's recommendations conflict with the KPSC's long-established support for including CWIP without any downward adjustment to the Companies' ROE. Mr. Tillman has presented no evidence that would suggest the KPSC's longstanding practice no longer benefits customers or would otherwise undermine a constructive regulatory policy that is widespread in the industry. Moreover, while CWIP is supportive of the Companies' credit standing, it does not allow recovery of a return on construction expenditures outside of a rate proceeding. As a result, there can be a significant lag between the time that expenditures are incurred and when they are included in CWIP, which is exacerbated for utilities with large capital expenditure programs, such as the Companies. Mr. Tillman fails to address these realities, which further disprove his assessment and recommendations.

Q158. MR. TILLMAN POINTS TO THE USE OF FORECAST TEST YEARS AS A RISK REDUCING RATE MECHANISM FOR THE COMPANIES. WOULD THIS FEATURE IMPLY A LOWER ROE FOR THE COMPANIES IN THIS CASE?

A158. No. As I point out in my Direct Testimony, investors recognize that the use of adjustment mechanisms and future test years is widely prevalent in the utility

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[180] *Construction Work in Progress for Public Utilities; Inclusion of Costs in Rate Base*, Order No. 298, FERC Stats. & Regs. ¶ 30,455 (1983), order on reh'g, 25 FERC ¶ 61,023 (1983).
[181] *Order No.679* at P. 115. *See also, Order No. 679-A* at PP. 114-115.

industry, and the relative impact is already considered in the data for my proxy group. As a result, any mitigation in risks associated with the Companies' ability to attenuate regulatory lag through adjustment mechanisms or its election of a future test year is already reflected in the results of the quantitative methods presented in my testimony. The KPSC's adjustment mechanisms and the Companies' election to use a future test year act to level the playing field, placing the Companies on equal footing with their peers in the industry. As a result, no adjustment to the ROE is justified or warranted.

Q159. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A159. Yes, it does.

VERIFICATION

STATE OF TEXAS)
) **SS:**
COUNTY OF TRAVIS)

The undersigned, **Adrien M. McKenzie**, being duly sworn, deposes and says he is President of FINCAP, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Adrien M. McKenzie

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 4th day of April 2017.

(SEAL)
Notary Public

My Commission Expires:

7/28/18

REBEKAH RENEA GARZA
NOTARY PUBLIC STATE OF TEXAS
MY COMM. EXP. 7/28/18
NOTARY ID 12990185-1

Exhibit No. 12

Allowed ROEs (RRA Averages)

STATE ALLOWED ROEs **Exhibit No. 12**

RRA INTEGRATED ELECTRIC UTILITIES

(24-Months Ended December 31, 2016)

	Company	State	Date	Allowed ROE	Adder / Penalty	Base ROE	
1	PacifiCorp	WY	01/23/15	9.50%	0.00%	9.50%	
2	Public Service Co. of CO	CO	02/24/15	9.83%	0.00%	9.83%	
3	PacifiCorp	WA	03/25/15	9.50%	0.00%	9.50%	
4	Northern State Power MN	MN	03/26/15	9.72%	0.00%	9.72%	
5	Wisconsin Public Service	MI	04/23/15	10.20%	0.00%	10.20%	
6	Union Electric	MO	04/29/15	9.53%	0.00%	9.53%	
7	Appalachian Power Co.	WV	05/26/15	9.75%	0.00%	9.75%	
8	Kansas City Power and Light	MO	09/02/15	9.50%	0.00%	9.50%	
9	Kansas City Power and Light	KS	09/23/15	9.30%	0.00%	9.30%	
10	Wisconsin Public Service Corp.	WI	11/19/15	10.00%	0.00%	10.00%	
11	Consumers Energy Co.	MI	11/19/15	10.30%	0.00%	10.30%	
12	Mississippi Power	MS	12/03/15	9.23%	0.00%	9.23%	
13	Northern States Power Co - WI	WI	12/03/15	10.00%	0.00%	10.00%	
14	DTE Electric Co.	MI	12/11/15	10.30%	0.00%	10.30%	
15	Portland General Electric Co.	OR	12/15/15	9.60%	0.00%	9.60%	
16	Southwestern Public Service Co	TX	12/17/15	9.70%	0.00%	9.70%	
17	Avista Corp.	ID	12/18/15	9.50%	0.00%	9.50%	
18	PacifiCorp	WY	12/30/15	9.50%	0.00%	9.50%	
19	Virginia Electric and Power	VA	(a)	(a)	(a)	10.00%	
20	MDU Resources Group	ND	01/05/16	10.50%	0.00%	10.50%	
21	Avista Corp	WA	01/06/16	9.50%	0.00%	9.50%	
22	Entergy Arkansas	AR	02/23/16	9.75%	0.00%	9.75%	
23	Virginia Electric and Power	VA	(b)	(b)	(b)	9.60%	
24	Indianapolis Power & Light Co.	IN	03/16/16	9.85%	-0.15%	10.00%	
25	El Paso Electric Co.	NM	06/08/16	9.48%	0.00%	9.48%	
26	Virginia Electric and Power	VA	(c)	(c)	(c)	9.60%	
27	Northern Indiana Public Service Co.	IN	7/18/2016	9.98%	0.00%	9.98%	
28	Kingsport Power Co.	TN	08/09/16	9.85%	0.00%	9.85%	
29	UNS Electric	AZ	08/18/16	9.50%	0.00%	9.50%	
30	PacifiCorp	WA	09/01/16	9.50%	0.00%	9.50%	
31	Upper Peninsula Power	MI	09/08/16	10.00%	0.00%	10.00%	
32	Public Service Co. of New Mexico	NM	09/28/16	9.58%	0.00%	9.58%	
33	Appalachian Power Co.	VA	10/06/16	9.40%	0.00%	9.40%	
34	Madison Gas & Electric Co.	WI	11/09/16	9.80%	0.00%	9.80%	
35	Public Service Co. of Oklahoma	OK	11/10/16	9.50%	0.00%	9.50%	
36	Wisconsin Power & Light Co.	WI	11/18/16	10.00%	0.00%	10.00%	
37	Florida Power & Light Co.	FL	11/29/16	10.55%	0.00%	10.55%	
38	Liberty Utilities	CA	12/01/16	10.00%	0.00%	10.00%	
39	Duke Energy Progress	SC	12/07/16	10.10%	0.00%	10.10%	
40	Black Hills Colorado Electric	CO	12/19/16	9.37%	0.00%	9.37%	
41	Sierra Pacific Power Co.	NV	12/22/16	9.60%	0.00%	9.60%	
42	Virginia Electric and Power	NC	12/22/16	9.90%	0.00%	9.90%	
43	Avista Corporation	ID	12/28/16	9.50%	0.00%	9.50%	
44	Appalachian Power Co.	VA	12/30/16	10.00%	0.00%	10.00%	
	Range of Reasonableness				**9.23%**	**--**	**10.55%**
	Midpoint					**9.89%**	
	Average					**9.76%**	

RRA INTEGRATED ELECTRIC UTILITIES

Notes

(a) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	2/18/2015	11.00%	1.00%	10.00%
Virginia Electric and Power	VA	3/12/2015	12.00%	2.00%	10.00%
Virginia Electric and Power	VA	3/12/2015	11.00%	1.00%	10.00%
Virginia Electric and Power	VA	3/12/2015	11.00%	1.00%	10.00%
Virginia Electric and Power	VA	4/21/2015	11.00%	1.00%	10.00%

(b) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	2/29/2016	11.60%	2.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	3/29/2016	9.60%	0.00%	9.60%

(c) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	6/30/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	6/30/2016	9.60%	0.00%	9.60%

Source: Regulatory Research Associates, "Major Rate Case Decisions," *Regulatory Focus* (Jan. 14, 2016, & Jan. 18, 2017).

Exhibit No. 13

Allowed ROEs (Utility Group)

STATE ALLOWED ROEs

UTILITY GROUP

	Company	(a) Allowed ROE		
1	Alliant Energy	10.50%		
2	Ameren Corp.	9.28%		
3	Avangrid, Inc.	9.23%		
4	Avista Corp.	9.50%		
5	Black Hills Corp.	9.37%		
6	CenterPoint Energy	10.18%		
7	CMS Energy Corp.	10.10%		
8	Consolidated Edison	9.00%		
9	DTE Energy Co.	10.10%		
10	Entergy Corp.	10.00%		
11	Eversource Energy	9.52%		
12	Exelon Corp.	9.60%		
13	NorthWestern Corp.	10.00%		
14	PG&E Corp.	10.40%		
15	PPL Corp.	NA		
16	Pub Sv Enterprise Grp.	10.30%		
17	SCANA Corp.	10.07%		
18	Sempra Energy	10.20%		
19	Southern Company	12.50%		
20	Vectren Corp.	10.28%		
21	WEC Energy Group	9.55%		
22	Xcel Energy Inc.	9.80%		
	Range of Reasonableness	**9.00%**	**--**	**12.50%**
	Midpoint	**10.75%**		
	Average	**10.0%**		
	Average-Baudino Group (b)	**10.0%**		

(a) The Value Line Investment Survey (Jan. 27, Feb. 17 & Mar. 17, 2017).
(b) Excluding Avangrid, Entergy, and PPL.

Exhibit No. 14

Earned ROEs (Utility Group)

EXPECTED EARNINGS APPROACH **Exhibit No. 14**

UTILITY GROUP

		(a)	(b)	(c)
	Company	**Expected Return on Common Equity**	**Mid-Year Adjustment Factor**	**Adjusted Return on Common Equity**
1	Alliant Energy	13.0%	1.0100	13.1%
2	Ameren Corp.	10.0%	1.0190	10.2%
3	Avangrid, Inc.	5.0%	1.0072	5.0%
4	Avista Corp.	8.0%	1.0190	8.2%
5	Black Hills Corp.	11.0%	1.0479	11.5%
6	CenterPoint Energy	17.0%	1.0211	17.4%
7	CMS Energy Corp.	13.5%	1.0356	14.0%
8	Consolidated Edison	8.5%	1.0179	8.7%
9	DTE Energy Co.	10.5%	1.0254	10.8%
10	Entergy Corp.	10.0%	1.0150	10.2%
11	Eversource Energy	10.0%	1.0186	10.2%
12	Exelon Corp.	9.5%	1.0320	9.8%
13	NorthWestern Corp.	10.0%	1.0214	10.2%
14	PG&E Corp.	10.0%	1.0325	10.3%
15	PPL Corp.	14.0%	1.0376	14.5%
16	Pub Sv Enterprise Grp.	11.5%	1.0184	11.7%
17	SCANA Corp.	10.0%	1.0251	10.3%
18	Sempra Energy	13.5%	1.0138	13.7%
19	Southern Company	11.0%	1.0179	11.2%
20	Vectren Corp.	12.5%	1.0274	12.8%
21	WEC Energy Group	11.0%	1.0171	11.2%
22	Xcel Energy Inc.	10.5%	1.0309	10.8%
	Average (d)			**11.2%**
	Average-Baudino Group (d,e)			**11.0%**

(a) The Value Line Investment Survey (Jan. 27, Feb. 17 & Mar. 17, 2017).

(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).

(c) (a) x (b).

(d) Excluding highlighted values.

(e) Excluding Avangrid, Entergy, and PPL.

Exhibit No. 15

Capital Structure (Electric Operating Companies)

CAPITAL STRUCTURE **Exhibit No. 15**

ELECTRIC OPERATING COS.

		At Fiscal Year-End 2016 (a)		
	Company	**Debt**	**Preferred**	**Common Equity**
1	Alabama Power Co.	51.8%	2.1%	46.2%
2	Ameren Illinois Co.	45.5%	1.1%	53.4%
3	Atlantic City Electric Co.	52.8%	0.0%	47.2%
4	Baltimore Gas & Electric Co.	44.9%	0.0%	55.1%
5	Black Hills Power	46.9%	0.0%	53.1%
6	Black Hills/Colorado Electric Utility Co	NA	NA	NA
7	CenterPoint Energy Houston Electric, LLC	NA	NA	NA
8	Central Maine Power Co.	39.0%	0.0%	61.0%
9	Cheyenne Light Fuel & Power	46.8%	0.0%	53.2%
10	Commonweath Edison Co.	44.6%	0.0%	55.4%
11	Connecticut Light & Power	43.5%	1.8%	54.6%
12	Consolidated Edison of NY	50.5%	0.0%	49.5%
13	Consumers Energy Co.	48.8%	0.3%	50.9%
14	Delmarva Power & Light Co.	50.3%	0.0%	49.7%
15	DTE Electric Co.	49.6%	0.0%	50.4%
16	Entergy Arkansas Inc.	55.3%	0.6%	44.1%
17	Entergy Louisiana LLC	53.4%	0.0%	46.6%
18	Entergy Mississippi Inc.	50.1%	0.9%	49.0%
19	Entergy New Orleans Inc.	49.1%	2.3%	48.7%
20	Entergy Texas Inc.	58.5%	0.0%	41.5%
21	Georgia Power Co.	47.9%	1.2%	50.9%
22	Gulf Power Co.	41.1%	5.6%	53.2%
23	Interstate Power & Light	46.8%	4.3%	48.9%
24	Kansas Gas & Electric	26.7%	0.0%	73.3%
25	Mississippi Power Co.	52.6%	0.5%	46.9%
26	New York State Electric & Gas Corp.	43.6%	0.0%	56.4%
27	Northern States Power Co. (MN)	47.9%	0.0%	52.1%
28	Northern States Power Co. (WI)	45.1%	0.0%	54.9%
29	NSTAR Electric Co.	43.4%	0.9%	55.7%

ELECTRIC OPERATING COS.

		At Fiscal Year-End 2016 (a)		
	Company	**Debt**	**Preferred**	**Common Equity**
30	Orange & Rockland	50.4%	0.0%	49.6%
31	Pacific Gas & Electric Co.	47.4%	0.7%	51.9%
32	PECO Energy Co.	43.0%	0.0%	57.0%
33	Potomac Electric Power Co.	50.5%	0.0%	49.5%
34	PPL Electric Utilities Corp.	45.5%	0.0%	54.5%
35	Pub Service Electric & Gas Co.	47.3%	0.0%	52.7%
36	Public Service Co. of Colorado	43.6%	0.0%	56.4%
37	Public Service Co. of New Hampshire	43.6%	0.0%	56.4%
38	Rochester Gas & Electric Corp.	45.1%	0.0%	54.9%
39	San Diego Gas & Electric	46.1%	0.0%	53.9%
40	South Carolina Electric & Gas	48.6%	0.0%	51.4%
41	Southern California Gas Co.	45.9%	0.3%	53.7%
42	Southern Indiana Gas & Electric Co.	43.4%	0.0%	56.6%
43	Southwestern Public Service Co.	49.6%	0.0%	50.4%
44	Union Electric Co.	48.9%	1.0%	50.1%
45	United Illuminating Co.	48.1%	0.0%	51.9%
46	Westar Energy	40.3%	0.0%	59.7%
47	Western Massachussetts Electric Co.	45.8%	0.0%	54.2%
48	Wisconsin Electric Power Co. (We Energies)	42.6%	0.5%	56.9%
49	Wisconsin Power & Light	47.0%	0.0%	53.0%
50	Wisconsin Public Service Corp.	44.8%	0.0%	55.2%
	Average	**46.8%**	**0.5%**	**52.7%**
	Minimum	**26.7%**	**0.0%**	**41.5%**
	Maximum	**58.5%**	**5.6%**	**73.3%**
	Excluding Min and Max	**46.9%**	**0.5%**	**52.5%**

(a) 2016 Form 10-K Reports, Annual Reports, and FERC Form 3-Q Reports.

Exhibit No. 16

Revised Walters Risk Premium

TREASURY BOND YIELD

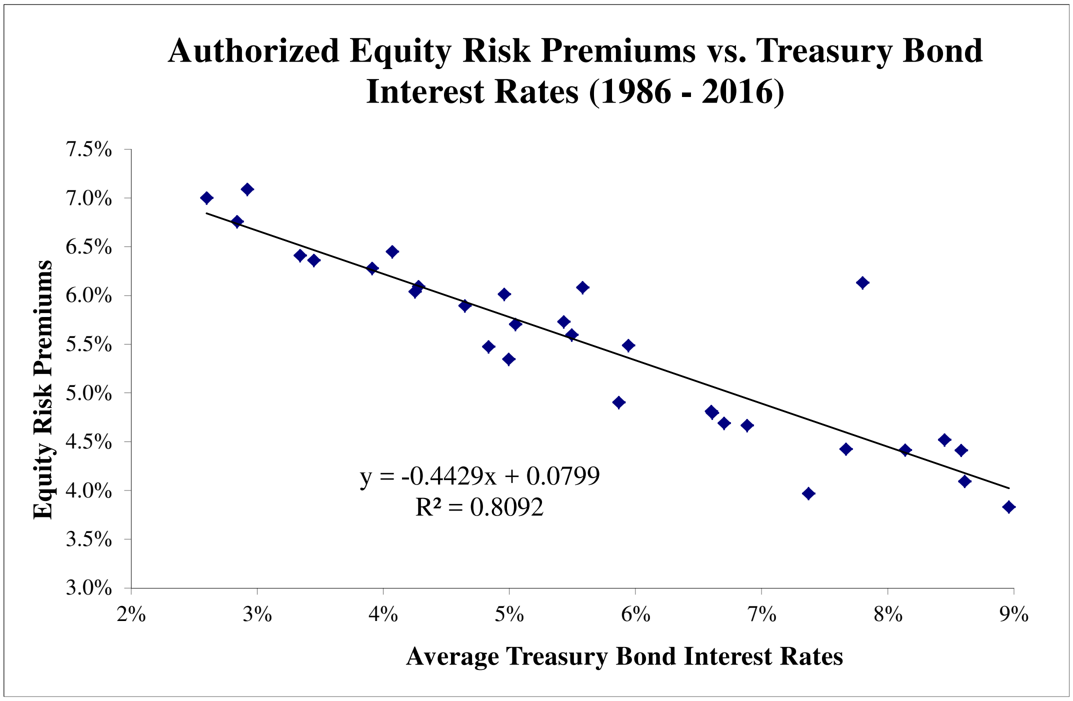
	(a) Treasury Bond Yield	(a) Authorized Electric Returns	(a) Indicated Risk Premium
1986	7.80%	13.93%	6.13%
1987	8.58%	12.99%	4.41%
1988	8.96%	12.79%	3.83%
1989	8.45%	12.97%	4.52%
1990	8.61%	12.70%	4.09%
1991	8.14%	12.55%	4.41%
1992	7.67%	12.09%	4.42%
1993	6.60%	11.41%	4.81%
1994	7.37%	11.34%	3.97%
1995	6.88%	11.55%	4.67%
1996	6.70%	11.39%	4.69%
1997	6.61%	11.40%	4.79%
1998	5.58%	11.66%	6.08%
1999	5.87%	10.77%	4.90%
2000	5.94%	11.43%	5.49%
2001	5.49%	11.09%	5.60%
2002	5.43%	11.16%	5.73%
2003	4.96%	10.97%	6.01%
2004	5.05%	10.75%	5.70%
2005	4.65%	10.54%	5.89%
2006	4.99%	10.34%	5.35%
2007	4.83%	10.31%	5.48%
2008	4.28%	10.37%	6.09%
2009	4.07%	10.52%	6.45%
2010	4.25%	10.29%	6.04%
2011	3.91%	10.19%	6.28%
2012	2.92%	10.01%	7.09%
2013	3.45%	9.81%	6.36%
2014	3.34%	9.75%	6.41%
2015	2.84%	9.60%	6.76%
2016	2.60%	9.60%	7.00%
AVERAGE	5.70%	11.17%	5.47%

IMPLIED COST OF EQUITY

Projected Treasury Bond Yield (b)	3.70%
Average Treasury Bond Yield Over Study Period	5.70%
Change in Bond Yield	-2.00%
Risk Premium/Interest Rate Coefficient (c)	-44.29%
Adjustment to Study Period Risk Premium	0.89%
Average Risk Premium Over Study Period	5.47%
Interest Rate Adjustment	0.89%
Adjusted Equity Risk Premium	6.35%
Projected Treasury Bond Yield (b)	3.70%
Implied Cost of Equity	**10.05%**

(a) Exhibit CCW-12.
(b) Walters Direct at 53.
(c) See regression data on page 2 of this Exhibit.

REGRESSION OUTPUT - TREASURY BOND YIELD



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.89957
R Square	0.80923
Adjusted R Square	0.80265
Standard Error	0.00410
Observations	31

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.00207	0.00207	123.01312	0.00000
Residual	29	0.00049	0.00002		
Total	30	0.00256			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.07993	0.00239	33.38910	0.00000	0.07503	0.08482	0.07503	0.08482
X Variable 1	-0.44289	0.03993	-11.09113	0.00000	-0.52456	-0.36122	-0.52456	-0.36122

REVISED WALTERS RISK PREMIUM

UTILITY BOND YIELD

	(a) Moody's "A" Rated Public Utility Bond Yield	(a) Authorized Electric Returns	(a) Indicated Risk Premium
1986	9.58%	13.93%	4.35%
1987	10.10%	12.99%	2.89%
1988	10.49%	12.79%	2.30%
1989	9.77%	12.97%	3.20%
1990	9.86%	12.70%	2.84%
1991	9.36%	12.55%	3.19%
1992	8.69%	12.09%	3.40%
1993	7.59%	11.41%	3.82%
1994	8.31%	11.34%	3.03%
1995	7.89%	11.55%	3.66%
1996	7.75%	11.39%	3.64%
1997	7.60%	11.40%	3.80%
1998	7.04%	11.66%	4.62%
1999	7.62%	10.77%	3.15%
2000	8.24%	11.43%	3.19%
2001	7.76%	11.09%	3.33%
2002	7.37%	11.16%	3.79%
2003	6.58%	10.97%	4.39%
2004	6.16%	10.75%	4.59%
2005	5.65%	10.54%	4.89%
2006	6.07%	10.34%	4.27%
2007	6.07%	10.31%	4.24%
2008	6.53%	10.37%	3.84%
2009	6.04%	10.52%	4.48%
2010	5.46%	10.29%	4.83%
2011	5.04%	10.19%	5.15%
2012	4.13%	10.01%	5.88%
2013	4.48%	9.81%	5.33%
2014	4.28%	9.75%	5.47%
2015	4.12%	9.60%	5.48%
2016	3.93%	9.60%	5.67%
AVERAGE	7.08%	11.17%	4.09%

INDICATED COST OF EQUITY

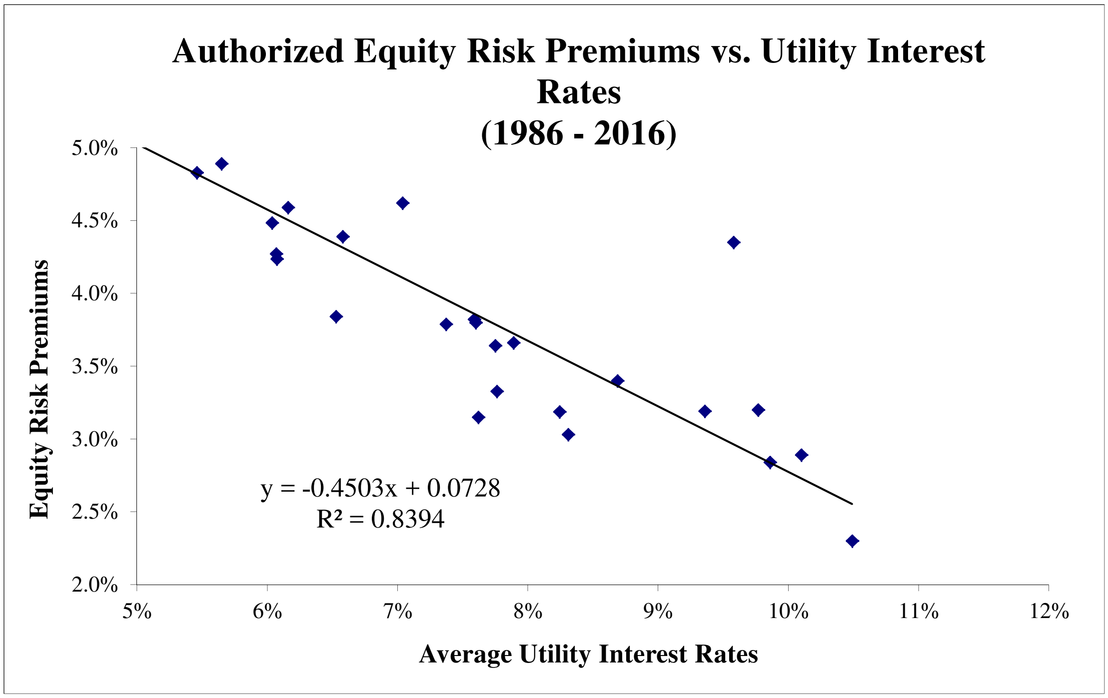
Current Baa Utility Bond Yield (b)	4.72%
Average Treasury Bond Yield Over Study Period	7.08%
Change in Bond Yield	-2.36%
Risk Premium/Interest Rate Coefficient (c)	-45.03%
Adjustment to Study Period Risk Premium	1.06%
Average Risk Premium Over Study Period	4.09%
Interest Rate Adjustment	1.06%
Adjusted Equity Risk Premium	5.15%
Current Baa Utility Bond Yield (b)	4.72%
Implied Cost of Equity	**9.87%**

(a) Exhibit CCW-13.

(b) Walters Direct at 53.

(c) See regression data on page 4 of this Exhibit.

REGRESSION OUTPUT - UTILITY BOND YIELD



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.91618
R Square	0.83939
Adjusted R Square	0.83385
Standard Error	0.00385
Observations	31

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.00224	0.00224	151.55784	0.00000
Residual	29	0.00043	0.00001		
Total	30	0.00267			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.07277	0.00268	27.14045	0.00000	0.06729	0.07825	0.06729	0.07825
X Variable 1	-0.45032	0.03658	-12.31088	0.00000	-0.52514	-0.37551	-0.52514	-0.37551

Appendix A

McKenzie Rebuttal Workpapers

(Exhibit is being provided in a separate PDF File)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)))))	**CASE NO. 2016-00370**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)))))	**CASE NO. 2016-00371**

REBUTTAL TESTIMONY OF
DAVID S. SINCLAIR
VICE PRESIDENT, ENERGY SUPPLY AND ANALYSIS
LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Filed: April 10, 2017

Q. Please state your name, position and business address.

A. My name is David S. Sinclair. I am Vice President, Energy Supply and Analysis of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies") and an employee of LG&E and KU Energy LLC. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut certain arguments concerning Curtailable Service Rider ("CSR") issues made by Dennis W. Goins, who testified on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC").

Q. Are you sponsoring any exhibits to your testimony?

A. Yes:

Rebuttal Exhibit DSS-1: Excerpt from 2017 Business Plan Generation & OSS Forecast

Q. Do you agree with Mr. Goins's recommendations #1 and #2 to this Commission on pages 6 and 7 of his testimony?[1]

A. No. Mr. Goins's recommendation to utilize the avoided cost method for determining the CSR credit completely ignores the timing of when future capacity is likely needed. This would result in increasing costs to non-CSR customers by, in effect, requiring them to "pay" in the form of CSR credits for capacity today that is potentially being avoided a decade or more from now. As explained in further detail in the rebuttal testimony of W. Steven Seelye, <u>when</u> a cost is being avoided is just as important as the <u>amount</u> of the cost being avoided. As I will explain in more detail,

[1] Goins at 6-7.

because the Companies likely have no need for additional capacity until after 2029, the avoided cost of future capacity would need to be highly discounted to reflect these future costs to today's customers. According to Mr. Seelye, reflecting this discounted value of future avoided capacity based on the 2016 Business Plan forecast that was filed as part of the 2016 Virginia Integrated Resource Plan ("IRP") would result in essentially the same CSR credits the Companies have proposed. However, the more recent 2017 Business Plan load forecast that was filed as part of this rate case shows no need for additional capacity for at least 30 years.[2] Assuming a need in the 31st year, Mr. Seelye calculated a discounted avoided cost that is approximately $2/kW-month lower than the CSR credits that the Companies originally proposed. Notably, at least one KIUC member has testified that reducing CSR credits could result in that customer reducing its operations in Kentucky, following Mr. Goins's avoided-cost approach to setting CSR credits could increase that risk,[3] in addition to the competitive harms to which KIUC's members testified would result from reduced CSR credits.[4]

As I stated in my direct testimony, the method for calculating the CSR credit proposed by the Companies results in the CSR customers receiving a credit based on the current cost of capacity that is in their rates that they are not allowed to fully utilize because they agree to curtail their load in certain circumstances.[5] This credit, in effect, reflects the depreciated cost of capacity that was avoided in the past. This

[2] *See* 2017 Business Plan Generation & OSS Forecast, Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(c)H, page 4 of 50 ("Absent unit retirements, no need for new capacity throughout the 30-year forecast period"). This page of the 2017 Business Plan Generation & OSS Forecast is also the second page of the attached Rebuttal Exhibit DSS-1.
[3] *See, e.g.,* Case No. 2016-00371, Simons at 4:15-20.
[4] Case No. 2016-00370, Riley at 4; Watson at 4-5. Case No. 2016-00371, Simons at 4.
[5] *See, e.g.,* Sinclair at 26:7-15.

results in today's non-CSR customers "paying" to CSR customers the capacity cost that they likely avoided in the last 10 to 20 years in order to encourage CSR customers to continue to participate. This is somewhat analogous to the ongoing revenue requirements of a supply-side generation resource.

Finally, Mr. Goins's recommendation seems to rely heavily on information from the Companies' 2014 Kentucky IRP and 2014 Demand Side Management ("DSM") plan. Much has changed in the three years since the 2014 Kentucky IRP was created, and it would be imprudent to ignore that information. For example, in the fall of 2014, the Companies cancelled their proposed 700 MW Green River Unit 5 natural gas combined cycle unit and withdrew the pending Certificate of Public Convenience and Necessity because the load forecast was reduced by over 300 MW due to eleven wholesale municipal customers giving notice to terminate their contracts. It would have been imprudent to ignore the municipal termination in determining the need for future supply-side capacity and it would be similarly imprudent to ignore the latest load forecast information to determine the CSR credit. Since the Companies' resource planning always incorporates the most recent information, I expect that the next DSM plan to be filed in early 2018 will reflect the latest load forecast and resource information as well.

<u>The Need for Additional Capacity in the Future</u>

Q. Based on the Companies' most recent publicly filed IRP, when will they likely need additional capacity?

A. As I described in my direct testimony, every year the Companies prepare a 30-year demand and energy forecast as well as a resource plan to reliably and cost-effectively meet our customer's future energy needs.[6] In Kentucky, these plans are filed as an IRP every three years, with the last one being in 2014 and the next one scheduled in 2018.[7] However, Virginia recently passed a law requiring utilities in that state to annually file an IRP by May 1. Therefore, the Companies' most recent publicly available IRP was filed in 2016 in Virginia.[8] Table 1 below is a copy of Table 12 from Exhibit 3 of the 2016 Virginia IRP, which indicates that the Companies are not likely to need additional generating capacity before 2029.

Table 1 – Resource Summary from 2016 Virginia IRP (MW, Summer)

	2016	**2017**	**2018**	**2019**	**2020**	**2028**	**2029**	**2030**
Forecasted Peak Load	7,356	7,430	7,485	7,234	7,234	7,457	7,485	7,513
DSM	(408)	(442)	(481)	(490)	(480)	(480)	(480)	(480)
Net Peak Load	6,948	6,988	7,004	6,744	6,754	6,977	7,005	7,033
Existing Resources[9]	7,815	7,819	7,819	7,819	7,819	7,819	7,819	7,819
Planned/Proposed Resources[10]	8	8	8	8	8	8	8	8
Firm Purchases[11]	317	317	317	152	152	152	152	152
Curtailable Load	136	136	136	136	136	136	136	136
Total Supply	8,276	8,280	8,280	8,115	8,115	8,115	8,115	8,115
Reserve Margin ("RM")	19.1%	18.5%	18.2%	20.3%	20.1%	16.3%	15.8%	15.4%
RM Shortfall (16% RM)*	216	174	155	292	280	21	(11)	(43)

*Negative values reflect reserve margin shortfalls.

[6] Sinclair at 4:3-4 and 21:19-21.

[7] *In the Matter of: 2014 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2014-00131, Order at 3 (Apr. 13, 2016).

[8] See LG&E Responses JBS Swift 1-6 and JBS Swift 2-12. The filing is available on the Commonwealth of Virginia State Corporation Commission's website, under Case No. PUE-2016-00053, at the following web address: http://www.scc.virginia.gov/docketsearch#caseDocs/135943.

[9] Existing resources include the retirement of Tyrone 3 in February 2013, Cane Run 6 in March 2015, Cane Run 4-5 in June 2015, and Green River 3-4 in September 2015, as well as the addition of Cane Run 7 in June 2015.

[10] Planned/Proposed Resources include Brown Solar in May 2016. 8 MW of the capacity of Brown Solar is assumed to be available at the time of peak.

[11] Firm Purchases include the Companies' share of OVEC as well as the planned capacity purchase and tolling agreement with EKPC's Bluegrass unit 3 for 165 MW through April 2019.

Q. I note that Table 1 indicates that 136 MW of curtailable load is forecasted to be a resource through at least 2030. What is the basis for this forecast?

A. The Companies' long-standing practice is to assume that, absent specific information to the contrary, all existing CSR customers will continue to participate at their current level in perpetuity and that no new customers will participate.

Q. Is the load forecast used in preparing the 2016 Virginia IRP the same as used to prepare the Companies' 2017 Business Plan that is the basis for the future test year in this case?

A. No. As I stated in my direct testimony, the load forecast used to prepare the 2017 Business Plan was completed in the summer of 2016, which was after the filing deadline for the 2016 Virginia IRP.[12] Therefore, the 2016 Virginia IRP load forecast was completed a year earlier, in the late summer of 2015. As I described in my direct testimony, each year the long-term load forecast is updated to reflect the most recent information regarding future economic conditions, demographics, major account activities, and energy efficiency developments.[13] As stated in the 2017 Business Plan Generation & OSS Forecast presentation that was supplied as Item H in Tab 16, Section 16(7)(c) of the original filing in this case, the 2017 Business Plan shows no need for <u>additional</u> capacity, absent unit retirements, for the entire 30 year forecast period.[14]

Q. Why did you stress the word "additional" capacity?

---

[12] Sinclair at 9:15-16.
[13] Sinclair at 4 -5.
[14] *See* Rebuttal Exhibit DSS-1 at 2.

A. I used the word "additional" because it may be more economical to retire existing generation units and acquire new capacity as a means to comply with environmental regulations in the future. However, the Companies are not likely to need additional capacity based on the forecasted future energy needs of our customers.

Q. Does resource planning involve more than just planning to serve load for the peak hour of the year?

A. Absolutely. Customers value reliability and economic energy every second of every hour of every year. This takes both good planning and good execution. Our long-term resource plans are developed based on an integrated hourly load forecast (8,760 hours in a year) which includes the entire load of CSR customers. As Table 1 showed, the ability to ask a CSR customer to curtail is viewed as a resource, not a reduction to the peak load forecast. This is because there is a risk that the customer will not curtail and the Companies will end up serving their load. Furthermore, because CSR customers expect the same reliability as non-CSR customers throughout the year, the ability to serve their load at all times must be considered when evaluating a host of resource planning issues such as scheduled maintenance plans, weather volatility, generating unit forced outage risk, variable energy costs, environmental emissions cost and constraints, daily ramping capability, and hourly operating reserve levels.

Q. Is it the Companies' desire for existing CSR customers to terminate their participation?

A. Absolutely not. As I have already stated and as can be seen in Table 1 above, the Companies' resource plan assumes that the existing participation in the CSR will continue for the next 30 years.

CSR in the Resource Plan

Q. Why do the Companies offer CSR?

A. The Companies constantly strive to maintain a portfolio of supply-side and demand-side resources that will allow us to reliably and economically serve our customers' energy needs throughout the year at the lowest reasonable cost. Because customers' energy demand can change dramatically over the course of the day and over the course of the year, this portfolio has resources that have varying operating and energy cost characteristics. Historically, to meet a portion of our customers' energy needs, particularly during extreme peak load conditions that occur infrequently, it has been lower cost to offer a discount in the form of the CSR credit to some customers in exchange for them agreeing to curtail their load for a limited number of hours and under certain system conditions. This avoids the need to procure supply side generation resources, which reduces costs for all customers. The source of compensation for the CSR credit is the shifting of some portion of the generation-related fixed costs to the non-CSR customers. This is appropriate because the non-CSR customers fund the CSR payment in lieu of paying for a portion of the fixed cost of a supply side resource that would otherwise have been needed. Either way, the non-CSR customers must pay for capacity, but the CSR credit should be a lower cost resource.

Q. Table 1 above forecasts 136 MW of CSR curtailments as a resource to meet customers' peak load needs. Is that the same quantity on which the financial credits to CSR customers are based?

A. No. All of the data shown in Table 1 is on an hourly integrated energy basis. As I stated, all of the CSR load is included in the peak load to be met so the 136 MW of curtailment potential represents the forecasted integrated energy of these customers. However, the CSR credits are based on the maximum curtailable billing demand (which is measured on a 5-minute or 15-minute basis) reduction for each customer. As Table 6 in my direct testimony illustrated, the billing demand reductions total 325 MW.

Q. Can you provide an example of why the volume difference is so large between the billing demand and the hourly integrated values?

A. Yes. It relates to a customer's hourly load factor, the frequency by which they operate near their peak billing demand, or both. Table 6 of my direct testimony shows that KU's largest CSR volume is associated with Company 3 with 193 MVA of curtailable load and that LG&E's largest CSR volume is associated with Company 1 with 41.5 MVA of curtailable load.[15] Table 2a below shows Company 3's hourly load factor distribution for the base period of July 1, 2015 through June 30, 2016. Company 3's hourly load factor is less than 60% in about half the hours in the year and less than 70% in about 79 percent of the hours. This means that the customer's load is seldom sustained at the billing demand volume that is used for the CSR financial credit. Furthermore, Table 2b shows that during any given hour in the base

[15] For purposes of this discussion, no material difference is assumed between MW and MVA values.

period, Company 3's 5-minute peak load was less than 100 MW (about half the CSR billing demand credit) about 39 percent of the hours and less than 160 MW for 99 percent of the hours.

Table 2a – Distribution of hourly load factors for KU Company 3		
Load Factor (%)	Number of Hours	Cumulative Percent of the Year
0 to <10	21	0
10 to <20	141	2
20 to <30	295	5
30 to <40	449	10
40 to <50	1,421	26
50 to <60	2,001	49
60 to <70	2,577	79
70 to <80	1,285	93
80 to <90	383	98
90 to 100	211	100

Table 2b – Distribution of hourly maximum demand for KU Company 3		
5-minute Peak Load (MW)	Number of Hours	Cumulative Percent of the Year
0 to <20	1,019	12
20 to <40	25	12
40 to <60	143	14
60 to <80	1,650	32
80 to <100	562	39
100 to <120	426	44
120 to <140	3,050	78
140 to <160	1,854	99
160 to <180	30	100
180 to 200	25	100

Tables 3a and 3b below show Company 1's distribution of hourly load factors and distribution of hourly maximum demands for the base period. While Company 1's hourly load factors were between 90 and 100 percent in about 87 percent of the hours, its maximum hourly demand was less than 30 MW in about 63 percent of the hours, as compared to its contract billing demand reduction of 41.5 MVA.

Table 3a – Distribution of hourly load factors for LG&E Company 1

Load Factor (%)	Number of Hours	Cumulative Percent of the Year
0 to <10	0	0
10 to <20	3	0
20 to <30	35	0
30 to <40	57	1
40 to <50	90	2
50 to <60	98	3
60 to <70	102	4
70 to <80	156	6
80 to <90	585	13
90 to 100	7,658	100

Table 3b – Distribution of hourly maximum demand for LG&E Company 1

5-minute Peak Load (MW)	Number of Hours	Cumulative Percent of the Year
0 to <5	609	7
5 to <10	99	8
10 to <15	79	9
15 to <20	174	11
20 to <25	414	16
25 to <30	4,161	63
30 to <35	1,832	84
35 to 40	1,416	100

Q. How does a CSR customer's hourly load factor compare to the hourly operation of a supply side resource?

A. Any one customer's load factor in a given hour is determined by the types of electrical devices being utilized and the factors that impact the moment-to-moment operation of those devices. It is my experience that very few individual customers have electrical equipment and utilization patterns that result in a large number of hours near their maximum demand with extremely high load factors, say in excess of 70 to 80 percent. This contrasts with a generating resource like a simple cycle combustion turbine that can easily operate at a 100 percent hourly capacity factor, assuming it is not following instantaneous load. Therefore, on an integrated hourly load basis, a utility will generally need a much greater quantity of curtailable load in order to equal the capacity value of a simple cycle combustion turbine. From a capacity planning perspective, the moment-to-moment "intermittency" of curtailable load is similar to the intermittency challenges associated with wind and solar generation.

Service Quality to CSR Customers

Q. What happens when the Companies ask a CSR customer to curtail their load?

A. The generation dispatcher follows established procedures to phone the CSR customer and request a physical curtailment. Depending on the customer's contract, the curtailment is a request to reduce load either to their contractual amount or by the contractual amount. Curtailment requests are logged and provided to the billing department.

Q. Does the generation dispatch center have any way to know if the CSR customer actually complies?

A. No, with the exception of the largest CSR customer, the generation dispatch center does not have the telemetry to confirm compliance in real time. Compliance is evaluated after the customers' meters are read at the end of the billing cycle.

Q. Will a CSR customer receive energy from the Companies even if they have been asked to curtail and they fail to do so?

A. Yes. Any failure to curtail as requested will be addressed through the monthly billing process. The CSR tariff specifies that non-compliance is subject to a monthly charge of $16 per kVA and "may result in termination of service under this rider."[16]

Q. Throughout his testimony, Mr. Goins seems to use the terms "non-firm", "interruptible", and "curtailable" interchangeably. Do you agree that these terms are interchangeable?

A. No. While some people might casually try to equate these concepts, based on my decades of experience in energy markets, they are much different. In particular, non-firm energy is not at all the same as interruptible or curtailable service.

Q. What does the term "non-firm" energy sale mean to you?

A. Based on my experience in energy marketing, firm energy sales have some degree of financial obligation and or consequences for both the buyer and the seller should the energy not be delivered or received whereas non-firm energy sales carry no such financial obligations for either party. In fact, per section 1.29 of the Federal Energy Regulatory Commission ("FERC") Pro Forma Open Access Transmission Tariff, a non-firm sale is defined as "An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller." FERC does not define a firm sale so a firm sale is essentially any sale that is not a non-firm sale.

Q. In what context do you typically see non-firm power sales?

[16] Citation to CSR tariff effective July 1, 2015.

A. The Companies participate in the real time energy markets both as a buyer and a seller and all of these economy sales and purchases with other utilities and with regional transmission organization (“RTO”) markets are non-firm.

Q. Would you say that the Companies’ service to CSR customers is firm or non-firm?

A. Most clearly they are firm sales. In addition to FERC’s definition, I think the Companies’ legal obligation to serve and the mechanics of the CSR tariff make it abundantly clear that the Companies’ service to CSR customers is firm. All the Companies can do is request that a CSR customer curtail its load, but if they don’t, the Companies nevertheless have to serve their load. Furthermore, during the non-curtailable hours of the year, there is absolutely no argument as to whether or not their service is firm. Lastly, the Companies have procured network transmission service from all of their generating units to all of the delivery points of CSR customers. This ensures firm delivery of energy for all hours in the year.

Q. Do you agree with Mr. Goins’s testimony on page 10, lines 1-10 that manufacturers do not require firm service to make their products and therefore prefer non-firm service?

A. No. In today’s modern advanced manufacturing facilities, power quality and reliability are typically of the utmost importance. Companies in this country are simply unlikely to accept truly non-firm service that could be “interrupted for any reason or no reason, without liability on the part of either the buyer or seller.”

Q. Is CSR service a “lower quality product” as stated by Mr. Goins on page 8, lines 16-17?

A. Absolutely not. The Companies are obligated to serve the entirety of a CSR customer's load at all times, even if they fail to curtail, and they receive their service from the same generators using the same network transmission service as the non-CSR customers. The only difference from other customers is that the Companies offer a CSR customer the opportunity to receive a credit on their monthly bill should they wish to curtail their load for a limited number of hours under certain system circumstances.

Q. Do you agree with Mr. Goins's testimony on page 10, lines 11-27 regarding the "fundamental principle" underlying how interruptible service should be priced?

A. Yes and no. Mr. Goins's statement that "interruptible load does not drive a utility's need for capacity" is quite broad and needs context.[17] If a customer's load can be interrupted at any time and is, in effect, non-firm energy, then from a resource planning perspective I would agree with him. For example, while the Companies may make off-system sales throughout the course of the year, we do not include the ability to make off-system sales in preparing and justifying our resource plans. In other words, off-system sales do not "drive [our] need for capacity." However, the Companies' CSR customers are not the same as off-system sales. Their load receives firm service 8,760 hours a year, which requires generation capacity throughout the year.

Q. Do you agree with Mr. Goins's statement on page 11, lines 5 – 6 that, "The embedded cost of CT capacity has no relationship to LG&E's cost of providing nonfirm service"?

[17] Goins at 10:13-14.

A. No. First, Mr. Goins is simply incorrect that CSR customers receive non-firm service. Their service is just as firm as the service provided to any other customer. When one moves beyond this false premise, then, as I explained in my Direct Testimony, the Companies' rationale for the credit being linked to the embedded cost of the capacity that the CSR customer is not supposed to utilize when asked to curtail is perfectly logical.[18] CSR customers simply do not have to pay for the fixed costs of generation resources to which they have limited access.

Q. Do you agree with Mr. Goins's testimony on page 12, lines 25 – 26 that "a utility is not required to build or acquire generating capacity to serve interruptible load"?

A. Not unless by "interruptible load" Mr. Goins means a load that can be interrupted 8,760 hours a year. Generating capacity is required every hour of the year to provide reliable, economic electric service to customers. I note that Mr. Goins goes on to state that "only firm service customers should pay for the demand-related costs of this capacity;"[19] because CSR customers are firm customers, I see no relevance to his testimony to the issues in this case regarding the dollar amount of the CSR credit.

Q. Can you provide a simple example of how an existing CSR customer utilizes and relies upon the Companies' generating capability?

A. Yes. While people in the industry often want to think about energy or demand over the course of an hour, the reality is that customers' demands are changing every second of the day, sometimes by large amounts. This requires power plants to instantaneously respond to these changing demands. Having no power plants means

[18] Sinclair at 26:7-15.
[19] Goins at 12:26-27.

no generating capability, which means no electricity is available for the customer. As I previously stated, KU Company 3 is the largest CSR customer. It so happens that their moment-to-moment load is particularly volatile.

Figure 1 shows an example of how this customer's load changes every 4 seconds over a 30 minute period. In this case, the Companies' generators had to ramp up by over 100 MW in a little over a minute, hold that level for about 2 minutes and then increase by almost another 100 MW in the next minute. In total, their load went from nearly 0 MW to over 200 MW in about 5 minutes and then stayed roughly at that level for at least the next 15 minutes. As a point of reference, it takes about 10 minutes for a fast-start simple cycle combustion turbine like Trimble County Unit 8 to start and sync to the grid.

Figure 1

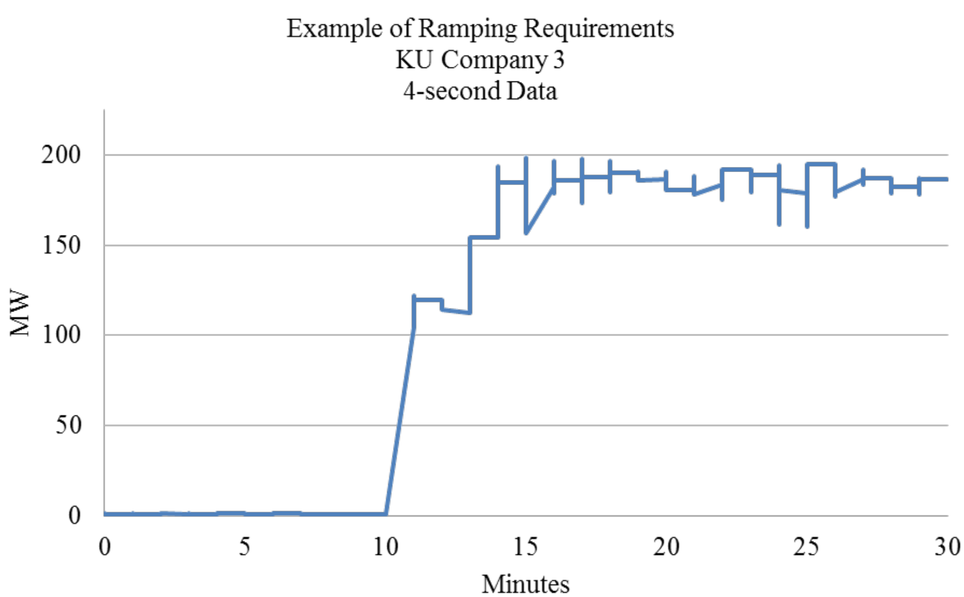
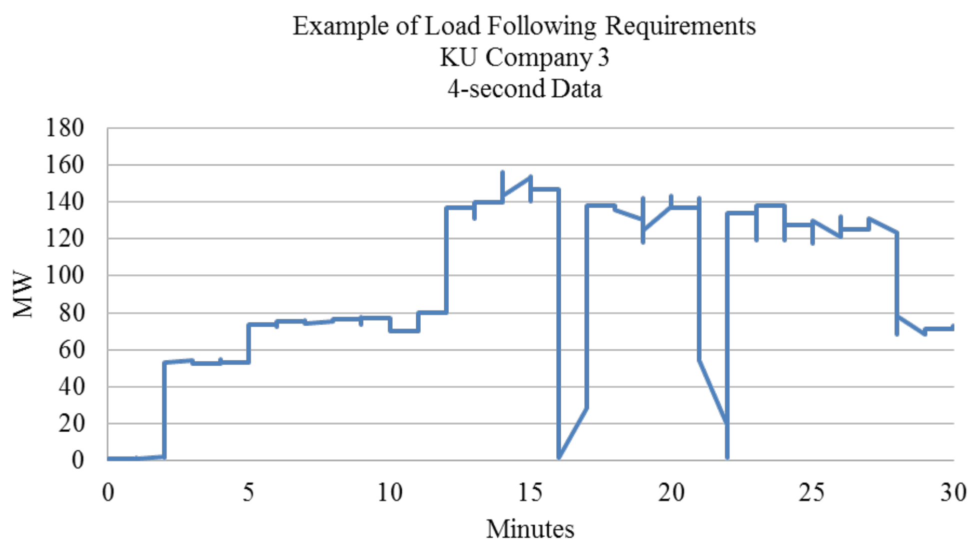


Figure 2 illustrates another example of how the Companies' generators are required to follow Company 3's load moment-to-moment over the course of 30 minutes. In this example, the load decreased from about 140 MW to about 0 MW in less than 1 minute, only to bounce back up to 140 MW just as fast about two minutes later. About 5 minutes later, this rapid load decrease/load increase cycle repeated itself.

The ability for Company 3 to operate their equipment in such a manner as illustrated by Figures 1 and 2 relies on the Companies' generating capacity and its ramping capability. Volunteering to be a CSR customer does not obviate this customer's reliance on the Companies' generation fleet.

Figure 2



Q. Do you agree with Mr. Goins's testimony on page 23, lines 23-26 that FLS load is "a valuable capacity resource for meeting system contingencies, industry performance criteria, unplanned outages and de-rates, and critical system events requiring automatic reserve sharing"?

A. No. Claiming to be a “valuable resource” by agreeing to reduce volatility in real-time load that one is capable of causing is a bit disingenuous. The two figures that I just discussed regarding the extreme ramping and load-following requirements of the CSR customer are those of the FLS customer. The Companies’ ability to activate the FLS interruption switch is meant to stop this volatility from occurring while the Companies sort out an unanticipated loss of generation. Responding to the large real-time swings in load caused by this FLS customer can be a challenge for a system the size of LG&E and KU, especially since the system resources were less and a different mix at the time the FLS customer came on the system. Over time, with new generating capacity, the Companies have developed increased capability to respond to these fluctuations.

Proposed CSR Credit

Q. Do you agree with Mr. Goins’s statement on page 17, lines 6-11 that, in effect, it is not possible to know which generating unit would have been dispatched to meet load that was curtailed?

A. No. As one who also has responsibility for generation dispatch, I can assure you that power plants are not randomly dispatched. Economic dispatch and the associated concept of marginal production cost are the foundation for real-time operations in both vertically integrated utilities like LG&E and KU as well as the basis for organized energy markets in RTOs. Given the CSR requirements that all available generation is dispatched or is in the process of being dispatched prior to asking for curtailments tells me that the energy curtailed would almost certainly come from a higher cost simple cycle CT. Furthermore, his recommendation to base the CSR credit on the avoided cost of a simple cycle CT is further evidence of the likely source of the energy that otherwise would be generated absent a curtailment.

Q. Do you agree with Mr. Goins's characterization on page 16, lines 21-26 and page 17, lines 1-2 of the basis for the Companies' switch to the embedded CT cost method for calculating the CSR credit?

A. No. His testimony cites my Direct Testimony regarding how the credit should be calculated, not the "basis for LG&E's switch to the embedded cost method" as the questioner asked. I clearly stated in my Direct Testimony (and I've discussed above) that the "basis" for the change was that the Companies have no need for <u>additional</u> future capacity.[20]

Conclusion

Q. Is it the Companies' intent to "gut" the CSR as asserted by Mr. Goins [page 24, lines 4-6]?

A. Absolutely not. The changes proposed by the Companies simply reflect the realities of the very flat load growth the Companies have been experiencing in recent years and which is forecasted to continue. As I've explained, the CSR is a substitute for a supply-side generating resource. The Companies simply do not need additional generating capacity for the next 30 years absent the retirement of some existing generation units. Therefore, the Companies proposed two changes to the CSR to address this: i) closing the rider to new customers effective January 1, 2017 and ii)

[20] Sinclair at 26:16-21 and 27:1-3.

moving to an embedded cost credit method for determining the amount of the CSR credit. I believe this fairly compensates existing CSR customers for the cost of the capacity they agree not to use during a limited number of hours each year under certain conditions. If one wants to utilize the avoided cost method as recommended by Mr. Goins, then one simply cannot ignore the timing of the costs that are to be avoided in calculating the avoided cost. As Mr. Seelye demonstrates, properly reflecting the 30+ year need for new capacity would result in an even lower CSR credit than what the Companies are proposing. Notably, the Companies are not proposing to set CSR credits on that basis in these proceedings.

Q. Is it your opinion that CSR customers should make some contribution to the Companies' generation fixed costs?

A. Absolutely. As I have stated, service to CSR customers is just as firm as it is to non-CSR customers, and CSR customers rely on the Companies' generation fleet throughout the year.

Q. Did you or other witnesses for the Companies raise "concerns" regarding other aspects of the CSR such as the notice period or conditions on which a curtailment may be called as mentioned in Mr. Goins's testimony?[21]

A. No. If the Companies had concerns about other aspects of the rider, we would have proposed changes to address them. Mr. Goins seems to be citing the Companies' factual responses to data requests or rider provisions and interpreting these as "concerns" of the Companies.

Q. Do you or the Companies share the "concerns" citied by Mr. Goins?

[21] Goins at 22:5-19.

A. No, which is why the Companies did not propose any changes to the fundamental operations of the CSR.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

David S. Sinclair
David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of April 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

Rebuttal Exhibit DSS-1

Excerpt from 2017 Business Plan Generation & OSS Forecast

PPL companies





2017 Business Plan
Generation & OSS Forecast

Generation Planning & Analysis
August 12, 2016

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(c)
H. Page 1 of 50
Sinclair

Rebuttal Exhibit DSS-1
Page 1 of 2

Key Changes in Planning Assumptions & Inputs vs. 2016 Plan

- Commodity prices are lower in 2017-2021
  - *Coal prices are 7-12% lower*
  - *Natural gas prices are 9-18% lower*
  - *Electricity prices are 13-17% lower*

- Native load energy requirements are lower (starting at 1.9% lower in 2017 and growing to 3.0% lower in 2021)
  - *Absent unit retirements, no need for new capacity throughout the 30-year forecast period*

- Variable O&M forecast is lower at Trimble, Mill Creek, and Ghent

- NOx emission rates updated to target CSAPR II compliance

PPL companies

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**)))))**	**CASE NO. 2016-00370**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**)))))**	**CASE NO. 2016-00371**

REBUTTAL TESTIMONY OF
JOHN P. MALLOY
VICE PRESIDENT, GAS DISTRIBUTION
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: April 10, 2017

Q. Please state your name, position and business address.

A. My name is John P. Malloy. I am Vice President of Gas Distribution for Louisville Gas and Electric Company ("LG&E"), which is the sister utility of Kentucky Utilities Company ("KU") (collectively, the "Companies"). I am an employee of LG&E and KU Services Company. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Have your responsibilities with the Companies changed since you filed your direct testimony in this case?

A. Yes. Effective January 15, 2017, I was promoted from Vice President of Customer Services (KU and LG&E) to Vice President of Gas Distribution (LG&E). I report directly to Lonnie E. Bellar, who is now serving as Senior Vice President of Operations for both Companies. Although my job responsibilities have changed, I am continuing to sponsor my previous testimony and responses to data requests in these proceedings, and I am offering the following rebuttal testimony on the same subject-matter areas I have previously addressed. A current copy of my CV is included with this testimony as Appendix A.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are to address testimony filed by certain intervenors concerning the Companies' proposal to deploy Advanced Metering Systems ("AMS") across the entirety of the Companies' service territories, as well as to address certain non-AMS customer-relations issues raised by several intervenors. I conclude the Commission should approve the certificates of public convenience and necessity ("CPCNs") and the cost recovery the Companies have requested for AMS because the intervenors have not provided a reasonable basis to dispute the Companies' evidence that full deployment of AMS would be prudent.

<u>The Companies' Proposed AMS Deployment Will Provide Net Benefits to Customers</u>

Q. Various intervenors have filed testimony alleging the Companies' proposed full deployment of AMS will result in net costs to customers or that certain customers will not benefit from the deployment. Is that correct?

A. The Companies appreciate the intervenors' points and perspectives, but as I discuss at length below, the Companies' proposed full deployment of AMS will indeed provide net benefits to customers taken as a whole, and will provide benefits to all customers, regardless of income or usage level. Indeed, the intervenors' testimony, and particularly that of Paul Alvarez on behalf of the Attorney General, has caused me to believe the Companies' proposed AMS deployment will be even more beneficial than the Companies' AMS Business Case indicated. In addition, Ronald L. Willhite, testifying on behalf of the Kentucky School Boards Association, unqualifiedly supported fully deploying AMS because of the benefits schools will be able to derive from the data AMS will provide.[1] I believe other customers will also benefit from the data AMS will provide, and the Companies will likely be able to use AMS data to offer improved rate structures and enhanced customer-service offerings.

Also, it is noteworthy that numerous other Kentucky utilities have deployed AMS, AMI (Advanced Metering Infrastructure), or AMR (Automated Meter Reading). Indeed, during the Commission's most recent administrative case concerning smart meters and smart-grid technology, nearly all electric utilities and natural gas local

[1] Willhite LG&E at 11:26-31; Willhite KU at 12:35-40.

distribution companies stated they had at least some form of AMR or AMI deployed, or had near-term plans to do so.[2] Two distribution cooperatives later obtained Commission approval to deploy AMI.[3] Therefore, there is nothing novel about the Companies' AMS proposal; rather, it is broadly consistent with AMR and AMI deployments made and Commission approvals granted to enhance efficiencies and better serve customers all across Kentucky.

Q. Mr. Alvarez states that he believes AMS can provide net benefits under certain conditions, but that the Companies' AMS proposal does not meet those conditions.[4] Do you agree?

A. I certainly agree that AMS, properly conceived and executed, can provide net benefits. But I do not agree that all of the conditions he stated were necessary are indeed necessary for AMS to produce net benefits, and I disagree with his assessment of which of his conditions are met regarding the Companies' proposed AMS deployment. Mr. Alvarez contends four conditions must be met for AMS to provide net benefits: "utilities highly motivated to deliver benefits, engaged customers conveniently able to take required actions, regulators who oversee post-deployment benefit delivery, and wholesale markets available for various parties to capture available economic value."[5] First, I do not agree with his fourth condition, namely that wholesale markets (by which he later explains he means Regional Transmission Organization ("RTO") markets) are

[2] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Report of the Joint Utilities at 77 (June 30, 2014) ("[A]ll of the utility members of the Joint Utilities have deployed advanced or smart technologies in different ways and degrees.").
[3] *In the Matter of: Application of Kenergy Corp. for an Order Issuing a Certificate of Convenience and Necessity to Install an Automated Metering and Infrastructure System*, Case No. 2014-00376, Order (Feb. 24, 2015); *In the Matter of: Application of Fleming-Mason Energy, Inc. for a Certificate of Public Convenience and Necessity to Install an Advanced Metering Infrastructure System (AMI)*, Case No. 2012-00361, Order (Oct. 11, 2012).
[4] *See, e.g.*, Alvarez at 7:19 – 8:20.
[5] *Id.* at 7:12-15.

necessary to ensure maximum AMS value. Though I agree there might be potential to use such markets to derive enhanced value from AMS, the Companies' AMS Business Case does not include any such benefits, and as I describe below, such benefits are not necessary to achieve net benefits from AMS.

Second, I disagree with the view that utilities have incentives not to deliver on claimed benefits and to game rate cases to ensure that any savings AMS does create do not appear in test years.[6] Certainly that is not true of the Companies. A utility would be shortsighted at best to come before its regulator to propose a major project with claims of benefits the utility has no intention of delivering; the damage to such a utility's credibility would be devastating in the long run. In addition, pricing pressures from distributed generation, particularly renewable generation, are real competitive forces that act on utilities like the Companies, so it is in the Companies' interest to propose additional costs only when they believe there are commensurate benefits to customers. In short, the Companies remain what they have long been: highly motivated to provide safe, reliable, and economical service to their customers, including through implementing AMS with an eye to achieving benefits. Moreover, the evidence of the Companies' service and customer-experience focus is demonstrated in detail in my direct testimony. Therefore, the Companies' AMS proposal satisfies Mr. Alvarez's first criterion for successful AMS deployment.

Third, as I discuss below, the Companies have evidence that customers with AMS are indeed engaged and able to implement energy-saving measures. Therefore,

[6] *See, e.g., id.* at 21:10 – 22:2.

the Companies' AMS proposal satisfies Mr. Alvarez's second criterion for successful AMS deployment.

Fourth, this Commission has a long history of ensuring utilities provide the service they are supposed to provide at fair, just, and reasonable rates. The Companies are certain that if the Commission approves the proposed full deployment of AMS, the Commission will ensure the Companies act prudently and treat customers fairly regarding AMS. Therefore, the Companies' AMS proposal satisfies Mr. Alvarez's third criterion for successful AMS deployment.

In sum, of the three of Mr. Alvarez's conditions that I believe truly are necessary to ensure a net-beneficial AMS deployment, all three are met regarding the Companies' proposed AMS deployment.

Q. The testimony of Lane Kollen on behalf of the Kentucky Industrial Utilities Customers, Inc. states that the proposed AMS deployment will result in a net cost to customers of at least $531 million nominal.[7] Do you agree?

A. No. I address each of Mr. Kollen's and Mr. Alvarez's assertions below to demonstrate that the Companies' AMS deployment will indeed provide net benefits.

<u>The Companies' Benefit Related to Non-Technical Losses Is Reasonable</u>

Q. With regard to non-technical losses, Mr. Kollen states that the Companies' AMS Business Case "claims the reduction in losses is $16 million over 20 years, which would be $320 million, not $489 million."[8] Is Mr. Kollen correct?

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[7] Kollen at 8:14-16.
[8] *Id.* at 9:3-4.

A. Mr. Kollen has correctly identified an oversight in the AMS Business Case document, but the Companies' asserted benefit of $489 million nominal remains correct. The AMS Business Case states, "The Company estimates recovery of non-technical losses to be approximately $16 million per year representing $489 million over 20 years."[9] The quoted sentence should say, "The Company estimates recovery of non-technical losses to be approximately $16 million *in 2020* and totaling $489 million over 20 years."[10]

Q. Mr. Kollen states concerning the AMS benefit related to non-technical losses, "The premise of this claim is that the Companies' revenues will increase if the non-technical losses are reduced, all else equal."[11] Do you agree with Mr. Kollen's assertion?

A. Mr. Kollen is mistaken about the Companies' position. Concerning this issue, my testimony states, "The additional revenues resulting from reducing non-technical losses ***will displace revenues*** the Companies would otherwise have to collect from other customers."[12] Similarly, the AMS Business Case states, "The end result [of reducing non-technical losses] is a net customer benefit from a more equitable system, where the true responsibility of payment is borne by the parties responsible for the energy usage."[13] Thus, the Companies are not claiming that the AMS benefit related to non-technical losses is increased revenue, but rather that those causing costs will be the ones paying them, which is indeed a benefit to customers who otherwise would have to

[9] Exhibit JPM-1 at 36.
[10] Emphasis added to show inadvertent omission.
[11] Kollen at 9:4-6.
[12] Malloy Direct at 22:23 – 23:2.
[13] Exh. JPM-1 at 36.

inequitably bear the cost of non-technical losses. In other words, customers who do pay their bills would indeed benefit from having revenue from those who are not currently paying their bills (or their correct bills) due to theft of service or undetected meter errors. That is the benefit from non-technical losses reflected in the AMS Business Case, and it is both real and substantial.

Q. Mr. Kollen notes that the EPRI study upon which the Companies relied in arriving at their AMS benefit from non-technical losses states, "Non-technical losses, by definition, are losses that are not accounted for and are, therefore, not subject to analytical measurement . . . there is no firm data to define the level of losses on an industrywide basis."[14] Did the Companies err in relying on the EPRI study when calculating a benefit based on non-technical losses?

A. No, it was reasonable to rely on the EPRI study. To the best of the Companies' knowledge, the EPRI study remains the most comprehensive recent attempt to estimate the magnitude of non-technical losses across the electric industry. Notably, Mr. Kollen did not cite to another study that is more recent or comprehensive to dispute the EPRI study. Moreover, it does not undermine the results of the study for EPRI to acknowledge that it simply is not possible for any utility to know with certainty the total amount of loss resulting from theft and meter-related errors. That is particularly true for utilities with older electro-mechanical meters that cannot provide the kinds of data AMS-type meters can provide to help alert utilities to possible theft or errors. Therefore, to avoid relying on anecdotes from any single or handful of utilities, unsupported subjective projections, or mere speculation, the Companies sought out the

[14] Kollen at 10:1-4.

best study available on which to base their estimate of non-technical losses. That study was and is the EPRI study.

But the Companies did not arbitrarily select a 2% non-technical losses value as supported by the EPRI study; rather, 2% of revenue is the estimate of non-technical losses the study repeatedly cites as reasonable, e.g., "Considering the referenced studies and reports, statistics and analysis, and the opinions of industry experts in revenue protection, a reasonable percentage for non-technical losses is 2.0%."[15] To increase the reasonableness of the AMS benefit calculation, the Companies assumed with full deployment of AMS that only 60% of actual non-technical losses would be identified and billed, and that only 60% of identified and billed non-technical losses would be collected. As noted in the Companies' discovery responses, their recent ratio of collected theft amounts to billed theft amounts is about 60%, so it is a well-supported multiplier.[16] Therefore, the total amount of non-technical losses the Companies have assumed they will detect, bill, and collect is not 2.0%, but rather 64% less than that (0.72%), which is a reasonable and well supported assumption.

Q. Do the Companies have non-technical losses today?

A. Yes. As noted in the Companies' discovery responses, the Companies currently detect and collect what would otherwise be theft losses on the order of hundreds of thousands of dollars each year. But those detections and collections depend entirely on meter readers noticing odd electrical arrangements or tips from customers concerning possible theft; as I noted above, our current electro-mechanical meters have no internal capability to report possible theft to the Companies. Similarly, the Companies do detect

[15] EPRI Report at 1-17 (attachment to response to KU KIUC 1-16(a) and LG&E KIUC 1-17 at 30).
[16] *See* responses to KU AG 2-81(c)(ii) and LG&E AG 2-89(c)(ii).

a level of metering-related errors each year, but the existing meters do not have the ability AMS meters have to detect and report internal or external irregularities that would indicate errors in need of resolution. Therefore, the Companies do indeed have non-technical losses, and are currently able to detect only a small fraction of their likely total non-technical losses. Fully implementing AMS will allow the Companies to detect more fully and rapidly the sources of non-technical losses, and likely to deter some amount of theft that would otherwise occur.

Q. Has any other intervenor addressed non-technical losses?

A. Yes. Paul Alvarez, testifying for the Attorney General, has addressed non-technical losses, as well. He concludes that it would be more reasonable to assume the Companies' non-technical losses are 1.9% than 2.0%, and that the Companies will be able to collect 30% of those losses rather than 36% as the Companies assumed.[17] On Mr. Alvarez's assumptions, the nominal AMS benefit from non-technical losses would be $362.9 million rather than $488.5 million, and the present-value benefit would be $182.9 million rather than $195.3 million.[18]

Q. Are Mr. Alvarez's assumptions regarding the AMS benefit from non-technical losses more reasonable than the Companies' calculations?

A. No. As noted above, the EPRI study stated that 2.0% was a reasonable assumption concerning non-technical losses. It is within the range of non-technical losses the EPRI study found likely and that Mr. Alvarez cited: "Non-technical revenue losses most likely fall within a much narrower range: 1.65% to 2.15%, depending on the utility and

[17] Alvarez at 20-21.
[18] *Id.* at 21.

service territory."[19] Moreover, the same paragraph of the EPRI study then states, "A 'mode' of 2% would appear reasonable and reflective of the impact on distribution utilities."[20] In contrast, Mr. Alvarez provides no empirical support for his proposal to use a 1.9% assumption. Therefore, the Companies' assumption of 2% non-technical losses is better grounded in the very source document Mr. Alvarez cites to support his 1.9% assumption.

With regard to Mr. Alvarez's assertion that it would be more reasonable to assume the Companies would be able to collect revenue for 30% of non-technical losses rather than 36% as the Companies assumed, he asserts, apparently based on two utilities' AMI business cases, that 25% is the typical recovery rate for IOUs.[21] He then splits the difference, choosing a 30% recovery rate as roughly the average of 25% and 36%.[22] But this approach overlooks several important points.

First, concerning ConEdison ("ConEd"), Mr. Alvarez asserts that ConEd assumed 1% theft losses and a 25% recovery of those losses.[23] Though that appears to be correct,[24] non-technical losses comprise more than theft, and ConEd's AMI Business Plan assumed a 20-year NPV benefit of $389 million for theft recovery and a $491 million benefit for reduced meter-related errors.[25] Therefore, ConEd's overall

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[19] EPRI Report at 1-18. *See* Alvarez at 20:16-17.
[20] EPRI Report at 1-18 (Attachment to Response to KIUC 1-16(a) at 31).
[21] Alvarez at 20-21.
[22] Alvarez at 20-21.
[23] *Id.* at 19.
[24] Attachment to AG's Response to KU DR 1, "ConEd AMI Plan.pdf" at pdf pages 52 and 63 (ConEd Study pages 48 and 59); attachment to AG's Response to LG&E DR 1, "ConEd AMI Plan.pdf" at pdf pages 52 and 63 (ConEd Study pages 48 and 59). Please note that a later version of the ConEd Study exists and contains substantially similar information. *See* ConEdison AMI Business Plan, dated Nov. 16, 2015. Available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=47337.
[25] *Id.* at pdf page 56 (ConEd Study page 52).

non-technical loss percentage appears to be higher than the 1% shown in Mr. Alvarez's table or its recovery rate is higher than 25%, or both.

Second, the Mass Electric data shown in Mr. Alvarez's table would seem to indicate a theft-reduction rate of 100%, presumably comprising some amount of recovery and some amount of deterrence, on a 1.5% reduction in theft losses for residential customers and a 1.0% reduction for commercial customers.[26] That is consistent with National Grid's Grid Modernization Plan document, which states, "The use of specific tools to detect theft will be enabled with AMI. The Company has assumed an increase in theft detection and consequent decrease in theft of approximately 1.5% of delivered energy for residential customers, and approximately 1% for customers with single phase small commercial meters."[27] (National Grid is the d/b/a for Massachusetts Electric Company and Nantucket Electric Company.) As discussed above, the Companies assumed a 36% recovery rate of 2.0% of non-technical losses, with a net of 0.72% recovery of non-technical losses; the Companies did not assert a benefit related to theft deterrence. The Companies' 0.72% assumption is conservative compared to Mass Electric's assumption that AMI will reduce theft by 1.5% for residential customers and 1.0% for small commercial customers.

Third, the Companies' 36% recovery rate has two components: 60% non-technical-loss identification and billing, and 60% collection of billed amounts. As

[26] Alvarez at 19.

[27] Attachment to AG's Response to KU DR 1, "National Grid Intro-Overview.pdf" at pdf page 43 (National Grid Study page 41); attachment to AG's Response to LG&E DR 1, "National Grid Intro-Overview.pdf" at pdf page 43 (National Grid Study page 41).
Also available at http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=15-120%2fGrid_Mod_PlanFinalRedacted_Boo.pdf.

noted above, the Companies' 60% collection rate is not arbitrary, but rather is based on the Companies' recent experience in collecting amounts billed related to tampering.[28] The 60% multiplier for non-technical-loss identification and billing is a reasonable discount to apply to total non-technical losses to recognize that, though AMS will dramatically improve the Companies' ability to detect and remedy non-technical losses, the Companies still will not be able to detect, bill, and collect all such losses. This is a more principled approach than simply splitting the difference between 25% and 36%.

Fourth and finally, the Companies' proposed AMS benefit related to non-technical losses compares favorably to two of the three examples Mr. Alvarez cites against the Companies. According to Mr. Alvarez's table, ConEd stated its AMI deployment would produce $870 million of present value benefits due to non-technical losses, and that ConEd has 12-month revenues of $8.172 billion.[29] Scaling ConEd's claimed benefit to align with the Companies' $2.438 billion in 12-month revenues would result in $259.6 million in present-value benefits, well in excess of the Companies' benefit calculation of $195.3 million. Similarly, Mass Electric, which has essentially the same annual revenues as the Companies, has a claimed $168.7 million present-value benefit resulting from non-technical-loss reductions, but that benefit was calculated over only 15 years. Notably, that value exceeds the 15-year non-technical-loss benefit the Companies calculated during discovery, namely $157.7 million, a value the Companies calculated assuming 2.0% non-technical losses and a 36% collection rate. Therefore, it would seem reasonable to assume that scaling up Mass Electric's

[28] *See* responses to KU AG 2-81(c)(ii) and LG&E AG 2-89(c)(ii).
[29] Alvarez at 19.

non-technical-loss benefit for 20 years would certainly bring it closer to the Companies' $195.3 million, and might exceed it.

In sum, Mr. Alvarez's assumptions about how to calculate an AMS benefit related to non-technical losses for the Companies are not as reasonable or well supported as the Companies' calculations.

<u>The Companies' Use of a 20-Year AMS Service Life Is Reasonable and within Industry Norms</u>

Q. Mr. Kollen asserts the Companies' AMS Business Case understates capital costs by $346 million nominal or more because it does not include the cost of replacing all AMS meters and gas indices within the study period.[30] Is Mr. Kollen correct?

A. No. Mr. Kollen makes several incorrect assertions to reach his conclusion.

First, he asserts, "The Companies estimate the *maximum* service life of the AMS meters is 20 years …."[31] That is incorrect. The Companies have assumed the *average*, not maximum, service life of AMS meters is 20 years; some will last longer, some not as long, but on average they will last 20 years.

Second, he asserts, "[T]he Companies propose a 15 year service life for depreciation purposes, which means that Mr. Spanos, their depreciation expert, believes that, on average, all new AMS meters will be replaced once within a 15 year period."[32] But what Mr. Spanos actually said was, "The most consistent average life within the industry for new technology electric meters is 15 years, with a maximum life potential life of 25 years."[33] In other words, Mr. Spanos assumed some meters

[30] Kollen at 10-11.
[31] Kollen at 10:11-12 (emphasis in original).
[32] *Id.* at 10:13-16.
[33] Spanos Direct at 15:7-9.

would last less than 15 years and some more than 15 years. Mr. Spanos has confirmed that view in his rebuttal testimony, in which he states, "As I state in my direct testimony, the 15-S2.5 survivor curve has a maximum life of around 25 years. Thus, this estimate forecasts that it would take around 25 years for all [AMS] meters to be replaced, not 15 years. The 15-S2.5 survivor curve forecasts that about half of the meters will be replaced within a 15 year period." Regardless, as I discuss further below in response to Mr. Alvarez, the Companies are far from alone among utilities assuming a 20-year service life for AMS meters.

Third, Mr. Kollen asserts, "[T]he Companies assumed that not a single AMS meter will be replaced during the 20 years."[34] Again, this is incorrect. The Companies assumed in AMS capital costs that they would need to have a spare inventory—precisely to replace meters as needed—of about 4% of the initially deployed quantity of AMS electric meters at a capital cost of $4.6 million and 10% of the initially deployed AMS gas indices at a capital cost of $2.4 million.

Fourth, he asserts the Companies have understated costs in the AMS Business Case by at least $346 million nominal because they should have included the cost of replacing every single AMS electric meter and gas index within the study period.[35] But if the Companies were to include the capital cost to replace every AMS electric meter and gas index, they would need to include the corresponding benefits associated with the additional life of the replaced AMS meters and indices. Indeed, as Mr. Alvarez

[34] Kollen at 10:17-18.
[35] *Id.* at 10:18 – 11:1.

stated in his testimony, "It is rational to assume benefits over an asset's useful life when calculating benefit projections."[36]

Q. Mr. Alvarez raises a related criticism, namely, "[A]lmost all IOUs' benefit calculations assume a 15-18 year useful AMS life[.]"[37] He further states, "I know of no AMS proposal approved by a regulator in which an IOU's benefit time period is as long as the Companies'. The longest I know of is 18 years."[38] Do you agree?

A. The examples Mr. Alvarez discusses in his testimony give reason to question his assertions. First, in the cost-benefit study Ameren Illinois submitted in the case Mr. Alvarez cites, the utility used a 20-year useful life for its AMI meters: "With respect to meter depreciation, Ameren Illinois has reviewed some of the largest AMI deployment plans in the United States, such as those by Duke Energy, Southern California Edison, DTE, and PG&E to base its AMI deployment on a useful life of 20 years for the AMI meter. … Moreover, Southern California Edison conducted product testing that concluded that the meter useful life would be 20 years or more."[39] Though Ameren's study period was only 20 years, which included an 8-year AMI deployment period and therefore did not include all of the benefits of the full 20-year life of Ameren's AMI meters, Ameren ensured the full 20-year-life benefits were ultimately reflected in its cost-benefit analysis by including a "terminal value" component to capture the net

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[36] Alvarez at 9:17-18.
[37] *Id.* at 9:10.
[38] *Id.*at 10:5-7.
[39] Attachment to AG's Response to KU DR 1, "Ameren Illinois Benefit-Cost Analysis.pdf" at pdf page 11 (Ameren Exhibit 2.4RO Page 7 of 52); Attachment to AG's Response to LG&E DR 1, "Ameren Illinois Benefit-Cost Analysis.pdf" at pdf page 11 (Ameren Exhibit 2.4RO Page 7 of 52).

benefits of its AMI meters beyond the study period: "The time horizon used for the business case was 20 years. However, a terminal value was also calculated to take into account the costs and benefits associated with the un-depreciated AMI infrastructure remaining beyond the 20 year period."[40] The terminal value Ameren Illinois calculated was significant: Of the $550 million of total net present value benefit asserted for the AMI deployment, fully $154 million of it was the terminal value, i.e., the net benefits the originally deployed AMI produced beyond the end of the 20-year study period.[41] So in the Ameren Illinois case cited by Mr. Alvarez, it is clear the utility proposed both to use a 20-year useful life for its AMI meters and to include the full 20 years of net benefits associated with those meters, even though some of those benefits occurred outside the 20-year study period.

Similarly, the AMI Business Plan ConEd submitted in the case cited by Mr. Alvarez used a 20-year cost-benefit evaluation period.[42] Although the 20-year evaluation period included six years of AMI project life (including five years of AMI system deployment),[43] the ConEd study does not appear to include capital costs to replace significant numbers of early-deployed meters; in other words, ConEd appears to have assumed at least 19 years of service life for deployed AMI meters, and likely 20.[44] Moreover, the ConEd study appears to have included AMI-related benefits for each of the 20 years in the evaluation period,[45] not 18 years as Mr. Alvarez asserts.[46]

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[40] *Id.*
[41] *Id.* at pdf pages 44-45 (Ameren Exhibit 2.4RO Pages 40-41 of 52).
[42] *See, e.g.*, ConEd Study at pdf page 44 (ConEd Study page 40) ("Over the 20-year evaluation period ….").
[43] *Id.*
[44] *See* ConEd Study at pdf page 61(ConEd Study page 57), Figure 5-3.
[45] *Id.*
[46] Alvarez at 10.

Indeed, evaluating AMI or AMS proposals over a 20-year benefit period is not at all uncommon. In addition to the two studies cited above, an independent Duke Energy Ohio Smart Grid Audit and Assessment conducted for the Staff of the Public Utilities Commission of Ohio used a 20-year benefit period and assumed a 20-year useful life for AMI meters.[47] Notably, Mr. Alvarez worked at MetaVu, the company that performed the Duke Ohio audit and assessment, and Mr. Alvarez took credit in his testimony for being a co-author of that report.[48] Duke Energy Indiana similarly used a 20-year study period in support of its smart-grid proposal.[49] The Maine Public Utilities Commission approved an AMI project for Central Maine Power Company based on a 20-year cost-benefit study period.[50] Also, BC Hydro in British Columbia, though not an IOU, used a cost-benefit analysis that assumed at least a 20-year service life for deployed AMI meters: its cost-benefit study period ran through its fiscal year 2033, but AMI meters were to begin deployment in 2011 and be complete by 2012, and the study did not include a wholesale replacement of meters prior to the end of the study period.[51]

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[47] Duke Energy Ohio Smart Grid Audit and Assessment dated June 30, 2011, at 70 ("MetaVu forecast annual benefits from 2009 to 2028 (20 years) to estimate the NPV of each.") and 83 ("It must be noted that smart meters will also need to be replaced after life cycle completion, estimated to be 20 years"), available at https://www.smartgrid.gov/files/Duke_Energy_Ohio_Smart_Grid_Audit_Assessment_201104.pdf. .

[48] Alvarez at 5:1-3 and fn. 2.

[49] *See* IURC Cause No. 43501, Order on Settlement at 6 (Nov. 4, 2009) ("Mr. Christopher D. Kiergan, Executive Consultant with KEMA, Inc., described and sponsored the SmartGrid cost/benefit model ("SmartGrid Model" or "'Model"), which generally captures the capital expenditures, O&M expenses, and associated benefits for 2009-2028, as well as calculating an overall 20-year net present value for the SmartGrid Initiative."), available at http://www.in.gov/iurc/files/43501order_110409.pdf.

[50] *See* Maine Public Utilities Commission, Docket No. 2007-215(II), Order at 6 (Feb. 25, 2010) ("CMP has provided a cost-benefit analysis that shows with the DOE grant, its proposed AMI investment will result in approximately $25 million in operational savings over 20 years"), available at https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2007-00215.

[51] *See, e.g.*, BC Hydro Smart Metering & Infrastructure Program Business Case at 1 and 33, available at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/projects/smart-metering/smi-program-business-case.pdf.

Therefore it was neither extraordinary nor unusual for the Companies to assume an AMS useful life and benefit period of more than 18 years.

Q. Mr. Alvarez asserts the Companies used a 21-year benefit period, which exceeds the 20-year average useful life of the Companies' proposed AMS system.[52] Is that correct?

A. Mr. Alvarez is correct that the Companies' AMS Business Case accounts for AMS costs and benefits from 2016 through 2039.[53] As noted in the AMS Business Case, this was not an oversight, but rather to ensure that a full 20 years of costs and benefits for the fully deployed AMS were included in the study; if approved, AMS will begin deployment in the third quarter of 2017, but will not be fully deployed until the end of 2019. A small amount of AMS-related benefits resulting from the early phases of the proposed deployment are included in the total benefits presented in the AMS Business Case for the years 2016-2018 (less than $7 million nominal). The real value of AMS begins to appear in 2019 because by the end of 2018 the entire LG&E AMS deployment will be complete and about half of KU's AMS deployment will be complete, with the entirety of KU's deployment to be complete by the end of 2019. Therefore, taking the same approach used by BC Hydro, which was similar to the approach taken by Ameren Illinois, the Companies used a cost-benefit study period that included 20 years of fully deployed AMS. In addition, this approach was reasonable due the Companies' inclusion of capital expense for some replacement AMS meters and gas indices, which capital is assumed to be spent by the end of 2019, i.e., those expenditures are not heavily discounted in present-value calculations, and therefore would be larger nominal capital

[52] *See, e.g.,* Alvarez at 9:9-10.
[53] *See* Exh. JPM-1 at 38.

dollars after 20 years. Finally, as noted by Mr. Spanos, AMS-type meters can have a maximum service life of 25 years, so the Companies' AMS meters could last well beyond the end of the study period. Therefore, the Companies' cost-benefit approach was reasonable.

But assuming solely for the sake of argument that Mr. Alvarez is correct that the Companies incorrectly used 21 years of benefits rather than 20, the Companies' AMS proposal would still result in net benefits. Simply ending the study period at the end of 2038 rather than the end of 2039 results in nominal benefits of $952.8 million and present-value benefits of $403.6 million, which are greater than the nominal cost ($550.9 million) and present-value cost ($387.9 million), respectively, of the Companies' AMS proposal.

Q. Is Mr. Alvarez correct that the Companies should use a 15-year service life rather than a 20-year service life for AMS meters in their cost-benefit analysis?

A. No. Mr. Alvarez asserts that "[t]he generally-accepted useful life for AMS is 15 years,"[54] but then presents a chart showing the AMS benefit years assumed by four different utilities (including the Companies), three of which are longer than 15 years.[55] Indeed, as I discussed above, two of the utilities cited, Ameren Illinois and ConEd, used service lives of 20 years, just as the Companies have done, and just as a number of other utilities have done.

Moreover, as I also noted above, Mr. Alvarez co-authored a 2011 study concerning Duke Energy Ohio's smart grid—a study performed for the Staff of the

[54] Alvarez at 10:3.
[55] *Id.* at 10:8.

Public Utilities Commission of Ohio ("PUCO")—that assumed a useful life of 20 years for AMI meters.[56] It stands to reason that if 20 years was a reasonable useful-life expectation in 2011 when Mr. Alvarez conducted his study for PUCO Staff, it is a reasonable expectation now, particularly because manufacturers have had an additional six years to improve and mature AMS technology since then.

Like Mr. Kollen, Mr. Alvarez cites the Companies' depreciation expert, Mr. Spanos, to insist the Companies should use a 15-year service life for AMS meters.[57] But as I noted in response to Mr. Kollen, Mr. Spanos's actual quote is, "The most consistent average life within the industry for new technology electric meters is 15 years, with a maximum life potential life of 25 years."[58] As shown above, numerous utilities—and Mr. Alvarez himself—have assumed AMI or AMS service lives of 20 years, which is well within the range cited by Mr. Spanos. And the Companies have stated they believe it is reasonable to use a 20-year depreciation life for AMS meters if that is the Commission's preference.[59]

Q. Does the Companies' experience with LG&E's Responsive Pricing and Smart Meter Pilot from 2007-2009 indicate a 15-year service life for AMS might be too long, as Mr. Alvarez suggests?[60]

A. No. As noted in the Companies' discovery responses in these cases, there was a problem with the LCD display screen—not the underlying metering or communications capabilities—on a particular type of meter LG&E used in the pilot; the Companies do

[56] *Id.* at 5:1-3 and fn. 2.
[57] Alvarez at 10:11-13.
[58] Spanos Direct at 15:7-9.
[59] Responses to LG&E PSC 3-44 and KU PSC 3-34.
[60] Alvarez at 11:1-9.

not propose to use the same meter in the AMS full deployment.[61] Moreover, as Mr. Alvarez notes, more than nine years have passed since the pilot began, and manufacturers have improved and matured the technology in the interim. Indeed, Mr. Alvarez presumably believed such meters could have a 20-year useful life when he co-authored the above-cited MetaVu report for PUCO Staff stating that AMI meters had a useful life of 20 years.

Q. Does a 5-year warranty for AMS meters indicate a 15-year service life for AMS might be too long, as Mr. Alvarez argues?[62]

A. No. The purpose of any standard manufacturer's warranty is not to insure a product for the entirety of its average useful life, but rather to provide a buyer assurance that if the particular item purchased has a manufacturing defect, the manufacturer will replace it. For example, a car, which requires a much more significant capital outlay than an AMS meter, typically will have a limited warranty with a much shorter duration than the average useful life of the car. There is nothing nefarious about that; rather, the warranty is a protection against buying a lemon. Similarly, most consumer electronics, which are much closer in price to AMS meters than cars, have warranty periods much shorter than 5 years. Again, that is not because many such items have average useful lives no longer than their warranties, but rather because most manufacturers' defects will manifest themselves within that time. So there is no reason to assume AMS meters will have a 15-year service life rather than a 20-year service life simply because manufacturers offer standard 5-year warranties; indeed, if service lives truly were tied

[61] *See* responses to LG&E AG 2-94 and KU AG 2-86.
[62] Alvarez at 11:10-12.

to warranties, one would presumably expect a 5-year service life for such meters, but Mr. Alvarez is not suggesting that.

Q. Do you agree with Mr. Alvarez that using a 15-year service life rather than a 20-year service life would have an "extremely significant" impact on the Companies' AMS cost-benefit projections?

A. It would certainly be significant. Of course, removing 25% of the benefits from many projects would cause them to become uneconomical, at least on a present-value basis. In this case, as the Companies stated in discovery, using a 15-year AMS service life reduces nominal benefits to $713.4 million and present-value benefits to $343.4 million, resulting in a net present-value cost of the AMS project of $35.1 million. But as noted above, numerous utilities have assumed 20-year service lives—indeed, Mr. Alvarez has done so in his past work—and such a service life is within the range cited by Mr. Spanos. Therefore, I recommend that the Commission not reduce the 20-year AMS service life presented in these cases.

<u>The Companies' AMS Benefit Based on Customer Savings from ePortal Are Well Supported by the Companies' Data and Industry Data</u>

Q. Concerning the $166 million nominal ePortal-related benefit that would result from full AMS deployment, Mr. Kollen stated, "[T]his assumes that the AMS is necessary for customers to somehow associate reduced consumption with energy savings, which it is not, or that time of use rates are available to all residential and commercial customers, which they are not."[63] Do you agree?

A. The Companies have not claimed AMS is strictly necessary for customers to save the energy accounted for in the ePortal benefit, but rather that customers who have AMS

[63] Kollen at 11:5-8.

meters and access to their detailed consumption data via ePortal do indeed reduce their electric consumption relative to what they would have consumed otherwise. The Companies' data from their DSM AMS customer offering shows this to be the case. According to the Bellomy Research study of AMS participants who had accessed the MyMeter Dashboard, fully 80% of responding participants indicated they had taken some energy-saving step or measure as a result of the AMS offering. Nearly 60% said they had upgraded to LED bulbs, and almost half said they had programmed their programmable thermostats.[64] Again, customers said they took these and other energy-saving measures because of the DSM AMS offering. Could these customers have purchased LED bulbs or programmed their thermostats absent AMS? Yes, but apparently they did not do so, at least not until they were presented with their energy consumption data in a fresh, detailed way through the MyMeter portal. Notably, Mr. Alvarez, who disagrees with the precise amount of the ePortal benefit, does not dispute that this effect exists and creates real benefits.[65]

With regard to Mr. Kollen's assertion about time-of-use rates, the Companies did not base any portion of the ePortal benefit on the availability of such rates, though deploying AMS meters could help the Companies develop such rates through the analysis and utilization of advanced meter data. Such rates could indeed produce additional benefits, as Mr. Alvarez asserts, but the Companies have not attempted to quantify such benefits.[66] These additional benefits would further enhance the business case for AMS.

[64] Exh. JPM-1 at 87.
[65] *See* Alvarez at 12 – 18.
[66] *See, e.g., id.* at 27.

Q. Mr. Kollen further claims that no part of the ePortal benefit can be considered a benefit because it reflects decreased revenues to the Companies, which the Companies in other contexts would consider to be a cost.[67] Do you agree?

A. No. Mr. Alvarez makes a related claim when he states the Companies erred in calculating their ePortal savings benefit as a percentage of customers' total bills rather than avoided fuel cost.[68] But I respectfully disagree with both Mr. Kollen and Mr. Alvarez on this issue.

The Companies' AMS Business Case attempts to quantify net savings to customers resulting from full AMS deployment; it is not a revenue-requirements analysis. It is true that not all customers will reduce their usage as a result of AMS, but some customers will, and those customers' savings are the savings the ePortal benefit quantifies. Unlike the DSM mechanism, which has a lost-sales cost recovery component that collects non-fuel revenue from sales assumed to be lost due to DSM programs between base-rate cases, the Companies do not have, and have not proposed, such a mechanism for base rates related to AMS. This means that the non-fuel benefit of energy savings between rate cases resides solely with customers, and it is therefore appropriate to count those savings when determining what customers' net savings will be from full AMS deployment.

Q. Relatedly, Mr. Alvarez has asserted that after the AMS is deployed the Companies will have no incentive to ensure energy conservation related to ePortal actually occurs.[69] Do you agree?

[67] Kollen at 11:11-18.
[68] Alvarez at 15 – 16.
[69] *Id.* at 16:20 – 17:3.

A. As I stated above, I believe the opposite is true: If the Commission approves full AMS deployment, it will be entirely in the Companies' interest to try to ensure customers benefit from it. The Companies do indeed face increasing competitive pressures to ensure they provide value commensurate with the cost of their service. Therefore, it would be imprudent, as well as foolhardy and dishonest, for the Companies to propose a project and then seek to undermine its cost-effectiveness upon implementation.

In addition, one of the virtues of the ePortal benefit is that it is entirely in customers' control, not the Companies'; it depends entirely on customers' choices, investments, and behaviors. All the Companies would have to do to facilitate the ePortal savings is ensure the ePortal continues to deliver timely and accurate information. Therefore, although it is clear the Companies do indeed have a clear and compelling motivation to do what they can to see customers realize the ePortal benefit, the Companies' incentives are ultimately of little or no consequence concerning whether customers actually take the steps necessary to achieve or exceed the projected ePortal benefit.

Q. Mr. Alvarez has also challenged the rate at which customers will access the ePortal as a ground for asserting the Companies' ePortal benefit is too high.[70] How do you respond?

A. The only actual data on this issue is the Companies' data from their own customers using the MyMeter portal. That data shows 48% of customers use the portal at least once, and that 36% of those customers become active users, i.e., a total of about 17% of customers become active users.[71]

[70] *Id.*at 13:2 – 14:8.
[71] *See* responses to LG&E Sierra Club 1-32 and KU Sierra Club 1-32.

In addition, the Tetra Tech analysis the Companies provided in discovery further supports the Companies' data-based assumptions about likely ePortal use. First, Tetra Tech reported that a utility with a similar AMS deployment to the one the Companies have proposed had ePortal registration by 56% of customers within two years of deployment, which is similar to the Companies' experience of 48%, which the Companies achieved in less than two years.[72] Second, the Tetra Tech analysis showed that when defining differently who is an active user of the Companies' MyMeter portal, i.e., a user who used MyMeter at least one use in each of three different months, the percentage of active MyMeter users is 33%, which is similar to the 36% of active users when defined as users who accessed MyMeter at least six times.[73] Thus, if ePortal registrations were actually 56% and active users were 33% of total enrollees, the total percentage of active users would be 18.7%, slightly higher than the Companies have assumed. In short, the Companies' assumption of 17% active ePortal users is supported by multiple data sources.

In contrast, Mr. Alvarez does not offer reliable support for his assertions about the percentage of the Companies' customers that will become active ePortal users, namely 2% (likely) and 5% (high and unlikely). Instead, Mr. Alvarez provides the following table, which he states shows "page views of all the other available 'My Meter' applications with true conservation potential":[74]

[72] Attachment to LG&E Response to ACM 2-24 at 6.
[73] *Id.*
[74] Alvarez at 14.

"My Meter" page	Page views	Unique Page views
"Charts View"	59	56
"Data View"	50	47
"Notifications"	48	42
"Profile"	44	41

Unfortunately, this table does not show what Mr. Alvarez believes it does. Mr. Alvarez took this data from the Companies' Advanced Metering Systems 2016 Annual Report filed in Case No. 2014-00003 on January 31, 2017, and in particular from Figure 6 on page 4 of the report.[75] As the explanatory text preceding the chart and in the chart itself make clear, the page-view data in that figure does not concern the MyMeter portal itself, but rather "the volume of customer interest in the websites the Companies have established to provide information on the Advanced Meter Service as well as educational materials on the MyMeter portal."[76] The descriptive text in the table for what Mr. Alvarez calls the "Charts View" entry, for example, states, "Welcome site for AMS customers featuring helpful tips and video tutorials about how to use the MyMeter 'Charts View.'"[77] All of the entries in that figure have active hyperlinks to the pages for which the figure provides page-view data. Those links lead to explanatory "help" pages, not actual MyMeter pages for obtaining usage or account data. Therefore, Mr. Alvarez is mistaken when he states, "[I]t's certainly possible that as few

[75] *Id.*
[76] Advanced Metering Systems 2016 Annual Report filed in Case No. 2014-00003 on January 31, 2017, at 4, available at http://psc.ky.gov/pscecf/2014-00003/rick.lovekamp@lge-ku.com/01312017100853/Closed/LGE_KU_AMS_Update_01-31-17.pdf.
[77] *Id.*

as 60 customers have ever used My Meter portal functions out of more than 900,000 customers served by the Companies."[78]

The data concerning actual MyMeter usage, which was on the next page of the report cited by Mr. Alvarez, is shown below in its entirety:[79]

MyMeter Analytics	2015[4]	2016
Accounts registered (enrollments)	908[5]	3,281
User Registrations (first time a user clicks into MyMeter)	514	2,484
Customer Energy Markers™	71	416
Customer Notification: Mobile phone notification set-up	34	73
System Notifications[6]	492	2,515
Customer Notification: Threshold alert set-up	54	173
Threshold notifications sent by system	653	12,663
Total Sessions within MyMeter Site	2,035	26,519
Sessions by new users	614	7,473
Sessions by returning users	1,421	19,046
Average session duration (minutes:seconds)	4:05	2:04
Page visits/session	2.96	1.8
Average Number of times MyMeter visited per month	508.8	2,209.92
Unique pageviews to MyMeter site	3,523	36,231
Total MyMeter site pageviews	6,027	47,742

This data shows AMS customers are considerably more engaged with MyMeter than Mr. Alvarez indicates, and supports the Companies' ePortal benefit.

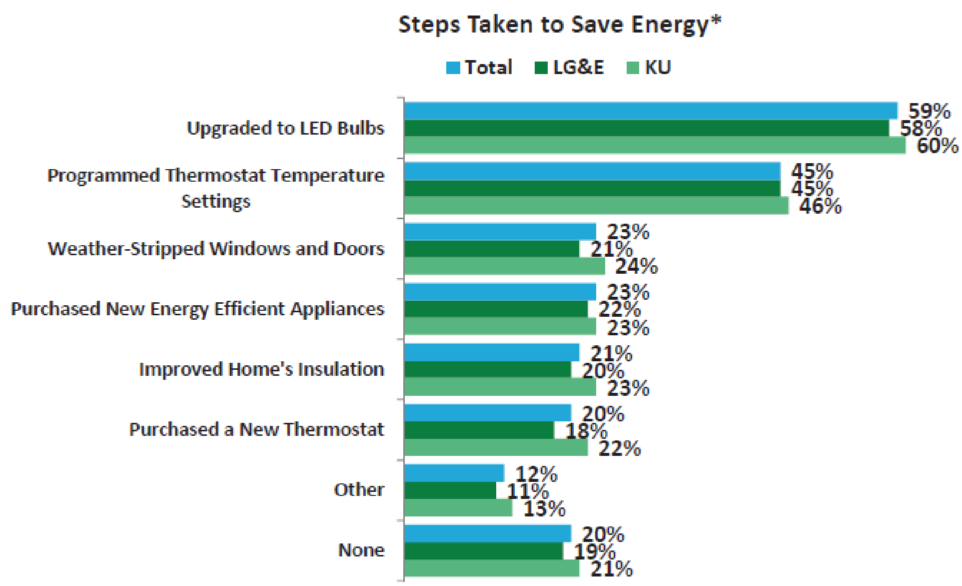
Q. Mr. Alvarez has also questioned the Companies' assumption that active ePortal users will reduce their bills by 3% through conservation.[80] How do you respond?

A. Mr. Alvarez states that he authored the Smart Grid Consumer Collaborative report upon which the Companies relied for their 3% assumption, and notes that his research showed that customers who had in-home displays reduced energy consumption between 5% and 15%.[81] But because the Companies are not proposing to use in-home

[78] Alvarez at 14:6-8.
[79] Advanced Metering Systems 2016 Annual Report filed in Case No. 2014-00003 on January 31, 2017, at 5.
[80] Alvarez at 14:12 – 15:9.
[81] *Id.*

displays, Mr. Alvarez doubts the Companies' 3% assumption, stating, "I know of no well-controlled study which indicates that accessing energy usage data via an internet-based portal delivers any statistically significant conservation benefits at all."[82]

Like Mr. Alvarez, I am not aware of a well-controlled study of the type to which he refers, but the Companies have something better: data from their actual customers. As I noted above in response to Mr. Kollen, fully 80% of DSM AMS participants who responded to the Bellomy survey and had accessed the MyMeter Dashboard indicated they had undertaken energy-savings steps because of AMS, including almost 60% who changed over to LED bulbs and almost 50% who programmed their thermostats (presumably to save energy).[83] The full set of responses is shown in the chart below:



Q8. Which, if any, of the following steps have you taken to save energy as a result of your participation in the Advanced Meter Service?
*Among customers who have accessed the MyMeter Dashboard (n=310)

Also, in-home displays are not necessary to convey information to customers in ways that will get their attention, particularly given the ubiquity of smart phones, which can provide customers usage and other data anytime and anywhere. As noted in the chart

[82] *Id.* at 15:7-9.
[83] Exh. JPM-1 at 87.

in the preceding answer concerning actual MyMeter usage, a number of customers have already signed up for various energy alerts to be sent to them by text or email, a capability that will remain and be enhanced in the full AMS deployment. Thus, the Companies have conservatively, not extravagantly, estimated energy savings for actively engaged customers at 3% of their total bills.

In addition, the Tetra Tech analysis the Companies provided in discovery shows that DSM AMS participants reduced their energy usage by an average of 6%.[84] This again is actual data from the Companies' own customers that supports assuming that active ePortal users will likely reduce their energy bills by at least 3% on average, a result the Tetra Tech report again shows is reasonable.[85] I respectfully recommend that the Commission rely on actual data concerning the Companies' customers where such data exists; here, the data amply supports the Companies' 3% savings assumption for actively engaged customers with AMS fully deployed.

Q. In view of Mr. Kollen's and Mr. Alvarez's criticisms and critiques of the Companies' ePortal benefit, what do you conclude?

A. I conclude that, if anything, the Companies might have underestimated the ePortal benefit. The evidence in this proceeding indicates it is likely that customers will meet or exceed the Companies' projected energy savings resulting from ePortal, which in the short run will redound to the benefit of the customers who reduce their usage. Therefore, I recommend the Commission deem reasonable the Companies' entire ePortal benefit of $166.3 million nominal ($66.6 million present value).

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[84] Attachment to LG&E Response to ACM 2-24 at 8.
[85] *See id.* at 3.

<u>Including the Carrying Costs of Retired Meters as a Cost of the AMS Deployment Would Be Unreasonable because the Companies Would Incur the Costs Irrespective of the AMS Deployment</u>

Q. Mr. Alvarez states he finds the Companies' other AMS costs and benefits to be reasonable, though he asserts the Commission should consider carrying costs of assets retired early due to AMS to be a cost included in AMS cost-benefit calculations.[86] Do you agree?

A. Though I agree the Companies' other AMS costs and benefits are reasonable, I do not agree the carrying costs of assets retired early due to full AMS deployment should be a cost included in AMS cost-benefit calculations. The reason is straightforward: The Companies would incur those costs regardless of whether they deployed AMS. If the Commission denied the Companies' requested CPCNs for AMS, the Companies' existing meter plant would remain in place, and presumably the Companies would continue to recover their carrying costs for that plant. If the Commission approved the CPCNs, the Commission would presumably approve the Companies' recovery of the costs of retired meters, including their carrying costs, because the current meters were prudent investments when made. The Companies would recover their carrying costs of existing meter plant in both scenarios. Therefore, the carrying costs are not costs of the AMS project because they are not caused by, and do not result from, the AMS project; rather, the Companies would incur and recover those costs regardless of whether the Companies fully deployed AMS. Only to the extent the Companies have proposed to accelerate recovery of those costs through a five-year recovery of a regulatory asset for the retired meters is it appropriate to add cost to the AMS project,

[86] Alvarez at 21:10 – 22:19.

and the net costs of that accelerated recovery are already reflected in the Companies' AMS business case. Therefore, because it would introduce error into the cost-benefit analysis to follow Mr. Alvarez's proposal to count the entirety of retired-meter carrying costs as a cost of the AMS project, I recommend against it.

<u>The Companies Agree AMS Could Have Benefits in Addition to those Quantified in the AMS Business Case, Data from the Fully Deployed AMS Will Be Necessary to Ensure the Companies Can Implement Programs and Rate Structures that Maximize Benefits</u>

Q. Although he does not believe his recommendations would result in full AMS deployment being net beneficial, Mr. Alvarez recommends that the Commission require certain programs be implemented if it approves the AMS deployment. Do you agree with Mr. Alvarez's recommendations?

A. Not as he has stated them, though I agree some of his recommendations are worth considering as options to achieve value for customers after the full deployment of AMS.

First, Mr. Alvarez suggests requiring the Companies to implement a Peak Time Rebate rate feature if the Commission approves AMS.[87] The Companies believe it is premature to commit (or be required to commit) to any particular rate approach or feature. Part of the point of implementing AMS is to gather data to better understand how customers use energy and what rate structures and features would best serve them while reflecting cost of service and ensuring cost recovery. To require a particular rate approach or feature without having that data is putting the cart before the horse. But the Companies do agree that improving rate structures based on data acquired from AMS will indeed provide benefits not quantified in the Companies' AMS Business

[87] *See, e.g., id.* at 24:10-12.

Case, and that benefits on the order of what Mr. Alvarez suggests, i.e., $40.9 million present value over 15 years, are plausible. Nonetheless, the Companies recommend against requiring Peak Time Rebates or any other rate structure or feature as a condition of approving full AMS deployment precisely because having AMS data before determining which rate-structure changes to implement will allow the Companies to propose rate-structure improvements that will work best for their customers.

Second, Mr. Alvarez recommends requiring the Companies to implement a High Bill Alert Program to alert customers when their usage is causing their estimated bills to approach customer-defined bill budgets.[88] As Mr. Alvarez further notes, the Companies already have a usage alert feature for MyMeter. But it can be denominated not just in kWh as Mr. Alvarez indicates, but also in dollars.[89] The Companies plan to retain and enhance this feature as part of the full AMS deployment; therefore, no requirement to do so is necessary.

Q. While discussing Peak Time Rebates, Mr. Alvarez recommends that the Companies consider the extent to which implementing AMS would allow the Companies or third-party aggregators to sell the demand response of the Companies' customers, e.g., the demand response capability associated with the Companies' residential and commercial load-control programs, into RTO markets.[90] How do you respond to this recommendation?

A. To the extent Mr. Alvarez is recommending the Companies join or be compelled to study joining an RTO, please see the rebuttal testimony of Lonnie E. Bellar addressing

[88] *See, e.g., id.* at 24:13-14.
[89] *Id.* at 32:8-15.
[90] *Id.* at 28 – 30.

Larry W. Holloway's arguments on this issue. That aside, the Companies will study such opportunities absent a mandate to do so. It is entirely in the Companies' interest to ensure the AMS deployment is economical, and if participating in demand-response markets would be net beneficial, the Companies will pursue it.

<u>The Commission Should Not Rely on Mr. Alvarez's Summary of His Proposed Adjustments to AMS Costs and Benefits</u>

Q. Mr. Alvarez argues the Companies' AMS proposal would be uneconomical even after accounting for additional benefits resulting from his recommendations, and provides an Appendix B that shows his calculations.[91] Should the Commission rely on his approach and calculations?

A. I do not believe the Commission can rely on Mr. Alvarez's calculations, which contain a number of errors and questionable assumptions.

First, as I explained at length above, numerous utilities, and Mr. Alvarez himself on behalf of PUCO Staff, have used 20-year study periods and AMS service lives when conducting cost-benefit analyses concerning AMS or AMI deployments. Therefore, I recommend the Commission consider AMS benefits and costs in years 16-20, which precludes using Mr. Alvarez's 15-year study period.

Second, although Mr. Alvarez says his recommendation is to use a 15-year rather than a 20-year cost-benefit study period, he begins by using the Companies' 20-year NPV costs (totaling $387.9 million) rather than the 15-year NPV costs the Companies provided in discovery (totaling $378.5 million). Therefore, by beginning with the wrong data he overstates 15-year AMS costs by $9.4 million NPV before he makes any adjustments to costs or benefits.

[91] *Id.* at 34 – 36 and Appendix B.

Third, Mr. Alvarez adds a $15.4 million cost to the AMS deployment to account for the carrying costs of the meters being replaced by AMS. But as I discussed above, those costs would be incurred regardless of whether the AMS project occurred; it simply is not a cost of the project, and the Commission should disregard it.

Therefore, before Mr. Alvarez begins to address benefits, he has overstated 15-year AMS costs by almost $25 million ($9.4 million + $15.4 million = $24.8 million).

Fourth, Mr. Alvarez subtracts from the Companies' proposed 20-year benefit figures what he believes are appropriate reductions to the non-technical losses and ePortal benefits. I provide extensive arguments above for why I believe those reductions are inappropriate.

But Mr. Alvarez then makes a clear mathematical error by subtracting $74.7 million from the total of the Companies' 20-year AMS benefits. That $74.7 million is the sum of the differences between the 20-year total present-value benefits calculated by the Companies ($418.1 million) and the 15-year total present-value benefits the Companies provided in discovery ($343.4 million). But Mr. Alvarez subtracts this value, i.e., he removes the entirety of the AMS benefits for years 16-20, after he has already reduced the Companies' non-technical-loss and ePortal benefits using 20-year present-value amounts. This approach double-counts what he believes are illusory savings in years 16-20: once when he removes the "excessive" savings through his 20-year non-technical losses and ePortal reductions, and again when he removes all the Companies' claimed benefits for years 16-20.

For these reasons, I recommend the Commission not rely on Mr. Alvarez's summary and conclusions.

Q. If the Commission desired to use a 15-year cost-benefit period for the fully deployed AMS, how would you recommend it be done?

A. Again, I would recommend against such an approach as disregarding five years of benefits and costs that should be included when considering the proposed AMS deployment. That aside, if the Commission did desire to consider the AMS deployment on a 15-year cost-benefit basis, I recommend the Commission begin with the 15-year cost-benefit summary the Companies provided in discovery, which showed a net cost of AMS full deployment of $35.1 million present value. I would then add the 15-year Peak Time Rebate benefit proposed by Mr. Alvarez, $40.9 million present value, but solely a proxy for rate-structure related benefits the Companies will implement after gathering sufficient customer data through AMS to formulate the most beneficial rate-structure changes, not because the Companies are committing to Peak Time Rebates. The result would be a 15-year net benefit of $15.8 million present value resulting from AMS full deployment.

Q. If the Commission agrees with the Companies that a 20-year cost-benefit period is appropriate for evaluating the proposed AMS deployment, do you have any proposed modifications to the Companies' filed cost-benefit data?

A. I do. Although I continue to believe the Companies' AMS Business Case presents a fair, reasonable, and accurate picture of the net benefits a full AMS deployment would provide, it would also be reasonable, though not necessary, to make certain adjustments based on Mr. Alvarez's testimony. In particular, if the Commission determined it was appropriate to consider a 20-year cost-benefit period that did not include 20 years of fully deployed AMS, but rather 20 years including the deployment period, I would recommend ending the study period at the end of 2038 rather than the end of 2039, resulting in a net present-value benefit of $15.7 million resulting from full AMS deployment (present-value benefits of $403.6 million minus present-value cost of $387.9 million). To that net benefit I would add the $40.9 million Peak Time Rebate benefit Mr. Alvarez proposes, again solely as a proxy for benefits from rate-structure changes, but not necessarily Peak Time Rebates per se. Although the $40.9 million value is a 15-year benefit estimate, I believe it is still a reasonable, albeit conservative, proxy for 20-year rate-structure-related benefits. These two adjustments to the Companies' AMS Business Case 20-year cost-benefit summary results in a net benefit of $56.6 million resulting from full AMS deployment.

Q. Would you recommend the Commission approve full deployment of AMS even if the Commission believed the deployment would result in net costs rather than net benefits based on the costs and benefits quantified in these proceedings?

A. I would. There are unquantifiable benefits and possible future benefits of AMS that that justify approving the proposed AMS deployment even if the Commission determines the AMS costs and benefits quantified in these proceedings would result in net costs on the order of what Mr. Alvarez claims, i.e., less than $90 million NPV over 15 years. For example, AMS data and functionality will enable enhanced customer service by providing more granular usage data to customer service representatives, who will be able to use that information to advise customers about possible rate options or energy-efficiency programs that might serve their needs. In addition, customer service will be enhanced by providing rapid service activations for move-ins and terminations for move-outs. Also, some customer service issues, such as possible metering errors, can be detected and addressed more quickly with AMS in place than without it.

But even more promising than the known unquantifiable benefits are the possible future benefits AMS could provide. It is a certainty that AMS will provide the Companies and their customers with significantly more usage data than is available today. In addition to aiding the Companies to formulate new and better-tailored rate structures, the data will enable customers to better understand their own usage characteristics, and therefore to exert more effective and informed control over their usage. And as the information technology revolution has shown time and again, the market constantly produces innovative and ingenious ways of harnessing data to provide new value and benefits. Therefore, there is ample reason to believe that the Companies' AMS Business Case understates the full value AMS will deliver to customers over 20 years. For that reason, I recommend the Commission approve the Companies' requested CPCNs and cost recovery for the full deployment of AMS, even if the Commission determines the costs of the deployment exceed the currently quantifiable benefits.

The Commission Should Reject Mr. Alvarez's Proposed Conditions of AMS Approval because Implementing Requirements before Having Data from Fully Deployed AMS Could Result in Suboptimal AMS Benefits

Q. In addition to Peak Time Rebates, a High Bill Alert Program, and a requirement to look into selling demand response into RTO markets, which you have already addressed, Mr. Alvarez asserts the Commission should attach several other

conditions if it approves full AMS deployment.[92] **Would you like to comment on those?**

A. Yes. Although Robert M. Conroy addresses Mr. Alvarez's cost-recovery and benefit-assurance rate mechanism proposals in detail, I would like to address Mr. Alvarez's recommendation that the Commission require "that AMS-related customer satisfaction programs be implemented, including tariffed, cost-based AMS meter opt-out fees and Green Button's 'Connect My Data' standard."[93] With regard to AMS opt-outs and related fees, I would simply reiterate my previous testimony on this issue, namely that opt-outs can compromise AMS benefits for all customers and would be contrary to the Commission's recently stated preference against offering opt-outs.[94] But I agree with Mr. Alvarez that if the Commission requires the Companies to offer opt-outs, those choosing to opt out should pay cost-based opt-out fees to compensate their fellow customers for the costs opt-outs create.

With regard to Green Button, the Companies noted in the AMS Business Case that the ability to implement Green Button's 'Connect My Data' standard is a benefit of full AMS deployment the Companies will explore. Furthermore, the Companies have already implemented the Green Button 'Download My Data' standard along with many utilities around the country to provide a standardized format of AMS interval data for use by customers. In addition to the Green Button standard, customers may also export the data in .CSV format, enabling a straightforward path to view the information in readily available software like Microsoft Excel and to transmit that data

[92] Alvarez at 37 – 50.
[93] *Id.* at 38:10-12.
[94] Malloy at 26 – 28.

to any energy-use analysis services customers choose. In so doing, the Companies seek to enable customer choice and understanding by giving them the tools and data to work with whichever providers they find to be most impactful to needs. Because the Companies are already planning to look into Green Button initiatives, I do not believe an affirmative obligation in this regard is necessary or appropriate.

Low-Income Customers Will Continue to Enjoy Existing Customer Protections after, and Will Receive Benefits from, Fully Deploying AMS

Q. Some advocates for low-income customers have expressed concern about AMS meters' remote service switches, and in particular the ability for such switches to disconnect a customer's service remotely.[95] Will current protections remain in place for customers concerning service disconnections?

A. Absolutely. As I stated in response to discovery requests on this issue, the Companies will continue to follow all applicable legal requirements concerning connection of service, disconnections, and reconnections, and will do so if the Commission approves the proposed AMS deployment just as it will if the Commission does not.[96] In particular, the Companies will continue to follow the procedures set out in their electric tariffs at Sheet No. 105.1, "Discontinuance of Service," at paragraph H. These procedures comply with all applicable legal requirements, and the Commission has repeatedly approved them as part of the Companies' electric tariffs. The Companies will also continue to follow their existing policy concerning residential disconnections during periods of cold weather.[97] And the Companies will continue to act on their clear

[95] *See* Testimony of Marlon Cummings at 19 – 22; Direct Testimony of Malcolm J. Ratchford at 15:13-18.
[96] *See, e.g.*, responses to LG&E AG 1-357, KU AG 1-332, and ACM 2-37.
[97] *See* response to ACM 2-43.

incentive to maintain service to customers by continuing to work with them and customer advocates on payment arrangements, LIHEAP, WinterCare, WinterHelp, WeCare, and other assistance programs for customers in need.[98]

But to the extent remote service disconnections—and reconnections—require additional policies and procedures, the Companies will do so taking into consideration customers' and advocates' actions to avoid disconnection. As I stated in discovery, the Companies are willing to work with advocates as the Companies design additional policies, procedures, and mechanisms regarding remote service disconnections and reconnections.[99] In addition, the Companies are committed to ensuring all disconnection policies, procedures, and practices comply with applicable Commission regulations.

Finally, it is important to reiterate that the same remote service switch that will make it possible to disconnect service remotely and almost instantaneously will also allow the Companies to reconnect service remotely and almost instantaneously. That will help ensure that customers who have arranged to have their service reconnected do not have to wait hours or even a day to have service back; rather, in a matter of moments after confirming the satisfactory arrangements, the Companies will be able to reconnect service. That is a real benefit for customers.

Q. Why is it not unfair to low-income customers for the Commission to approve a disconnection charge of $14.22 and a reconnection charge of $14.22 if AMS will decrease the costs of disconnections and reconnections?[100]

[98] *See* response to ACM 2-37.
[99] *See id.*
[100] *See* Cummings at 22.

A. The Companies will continue to incur the costs of disconnections and reconnections reflected in the $14.22 charge for each service until AMS is fully deployed in each service territory. If not already addressed in a base-rate proceeding, the Companies will address the disconnect-reconnect charge in a separate tariff filing when the costs of remote disconnections and reconnections are better understood post-deployment. That will help ensure that all customers, low-income or otherwise, will pay only genuinely cost-based disconnect-reconnect charges.

Q. Several low-income advocates have expressed concern that low-income customers will not receive benefits from AMS due to lack of access to the Internet,[101] and that the low participation of low-income customers in the DSM AMS offering indicates that low-income customers are unlikely to use ePortal tools and engage with AMS data.[102] How do you respond?

A. Although access to ePortal and responding by taking appropriate energy-saving measures is certainly one way customers will benefit from AMS, it is far from the only way customers—including low-income customers—will benefit from AMS. First, reduced operational costs resulting from AMS will redound to all customers' benefit. Second, enhanced identification and recovery of non-technical losses will again redound to all customers' benefit, including low-income customers. Third, reduced post-storm and other service-restoration times resulting from AMS data will be a benefit for all customers, including low-income customers. Fourth, to the extent AMS data allows the Companies to formulate rate structures that better reflect underlying costs based on much better customer-usage data from AMS, all customers will benefit,

[101] *See, e.g.*, Ratchford at 15:1-12; Cummings at 24 – 25; Prefiled Direct Testimony of Cathy Hinko at 17:3-13.
[102] Cummings at 26:10-12.

and particularly those low-income customers who have above-average usage and are effectively subsidizing low-usage customers. Fifth, AMS-related features like usage and bill alerts require only a phone capable of receiving text messages, which devices are typically broadly available. Therefore, although the Companies do not dispute that having Internet access will help customers maximize potential AMS benefits, having Internet access is not at all necessary to receive most categories of AMS benefits.

Customer Relations Issues

Q. According to several of the KIUC's witnesses, the Companies' personnel did not consult with KIUC members before proposing reduced CSR credits in this proceeding.[103] How do you respond?

A. We value all of our customers, and the KIUC's members are no exception. Indeed, the Companies have Major Accounts Representatives whose sole responsibility is to interact regularly with our largest customers to understand their needs, address their concerns, and provide them pertinent information. So to the extent the KIUC's witnesses' testimony implies that the Companies do not value or regularly communicate with their largest customers, it would be more accurate to say the Companies highly value such customers and make a point of regularly communicating with them. Indeed, as Mark Watson of Alliance Coal testified, "KU has also provided us with excellent customer service. KU is a large company and as a customer that is always expanding and moving, we require communication with multiple groups inside KU. Whether we are planning for the future, scheduling an outage, or need help tracking down a system fault, KU has been there to support our needs."[104]

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[103] *See, e.g.*, Goins at 15:8-10; Riley at 6:1-4.
[104] Watson at 6:20-7:2.

But concerning the specific assertion that the Companies did not consult with KIUC's members regarding the particular CSR credits the Companies were planning to propose, it is correct that the Companies did not solicit KIUC's members' views on the credits to propose in these cases. The Companies and the KIUC have been involved in a number of rate cases together, and have engaged in significant settlement negotiations that included CSR credits and tariff requirements. It is reasonable to say the Companies are well aware of KIUC's and its members' desires concerning CSR. Indeed, KIUC and its members are well capable of communicating their views to the Companies on numerous issues, and they do so frequently. But just as the Companies are aware of KIUC's views, they are similarly aware of their other customers' desire not to pay more for CSR credits than the value of the Companies' ability to curtail participating customers.

Q. Thomas J. Prisco, testifying on behalf of the Department of Defense and All Other Federal Agencies, stated that if LG&E had worked with Fort Knox earlier to determine what would be necessary to serve the Fort at 69 kV instead of the current 34.5 kV, "[I]t's highly possible the cost analysis which justified the original distributed generation would have failed [due to the structure of transmission-level rates]."[105] Did LG&E work with Fort Knox to determine what would be required to serve the Fort at 69 kV rather than 34.5 kV?

A. Yes. In 2006, prior to the Fort's installation of large amounts of distributed generation, LG&E conducted a study to determine what would be necessary to serve the Fort at 69 kV. In particular, LG&E proposed to serve the Fort with redundant 69 kV feeds (one

[105] Prisco at 8:7-18.

an LG&E feed and another a KU feed) to ensure better reliability for the Fort. In short, the Fort determined it was not interested in incurring the cost to receive such service. Making that determination was and is the Fort's prerogative, but it is not accurate for Mr. Prisco to say, "If efforts like these were taken earlier, it's highly possible the cost analysis which justified the original distributed generation would have failed."[106] LG&E offered to serve the Fort at 69 kV before the Fort made its sizeable investment in distributed generation; the Fort declined the offer.

That aside, LG&E has for a number of years engaged the Fort in extended and extensive discussions concerning the Fort's electric and gas service, as well as related issues. LG&E will continue to engage constructively with the Fort, and looks forward to serving the Fort for decades to come.

Q. Daniel Frockt, testifying on behalf of Louisville/Jefferson County Metro Government, states, "LG&E charges Louisville metro for 23,645 street lights. I do not have independent verification that all of those lights are actually located within the jurisdictional limits of Louisville metro."[107] Has there been an audit of Louisville Metro's streetlights to ensure LG&E is billing Louisville Metro correctly?

A. Yes. LG&E conducted a streetlight audit for Louisville Metro in 2009. That audit determined that 23,675 streetlights were being correctly billed to Louisville Metro. That would tend to indicate that the 23,645 lights for which LG&E currently bills Louisville Metro are indeed inside the territorial boundaries of Louisville Metro.

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[106] *Id.* at 8:17-18.
[107] Frockt at 4:9-11.

Lexington-Fayette Urban County Government Lighting Concern

Q. Douglas B. Jester, testifying for Lexington-Fayette Urban County Government ("LFUCG"), "[N]ote[s] that it does not appear that Kentucky Utilities has collaborated with its lighting customers to determine what new lighting offerings would be introduced into its tariff."[108] He further recommends the Commission require KU to consult with LFUCG and other customers concerning "whether its lighting offerings adequately meet the needs of the customers and reflect advancements in technology."[109] How do you respond?

A. The Companies did not collaborate with customers concerning the particular lighting offerings proposed in these cases, but the Companies have received input from lighting customers in the past. KU in particular has worked with LFUCG concerning their lighting concerns, and engaged in an LED pilot program with LFUCG that was the subject of certain discovery requests.[110] Certainly KU is open to discussing lighting and other service matters with LFUCG, as it has done in the past, and no Commission order in that regard is needed.

Conclusion and Recommendation

Q. What is your recommendation to the Commission?

A. Having now read and addressed the intervenors' testimony concerning the Companies' proposed full deployment of AMS, I again recommend the Commission approve the Companies' requested CPCNs and cost recovery. Indeed, as I noted above, I believe on either a 15-year or 20-year study period, AMS proves to be net beneficial for

[108] Jester at 25:15-17.
[109] *Id.* at 25:20-23.
[110] *See, e.g.*, KU Response to LFUCG 1-15.

customers. And even if the Commission found AMS not to be net beneficial based on quantifiable benefits, there are ample unquantified and currently unquantifiable benefits that will result from having AMS-provided data to support approval of full AMS deployment.

With regard to low-income advocates' concerns, it is clear the Companies will continue to adhere to all current requirements regarding protections for customers facing service disconnection, and the ability to rapidly and remotely reconnect service will be a benefit to the customers these advocates serve. In addition, there are numerous other AMS benefits low-income customers will receive, including improved service restoration times and relatively lower costs resulting from operational efficiencies and improved collections of non-technical losses.

Therefore, I conclude the Companies' proposed full deployment of AMS will provide benefits, both quantified and otherwise, exceeding its costs. It merits the Commission's approval.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John P. Malloy**, being duly sworn, deposes and says that he is Vice President – Gas Distribution for Louisville Gas and Electric Company and Kentucky Utilities Company, an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

John P. Malloy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of April 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

APPENDIX A

John P. Malloy
Vice President, Gas Distribution
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-4836

Education

Indiana University, Master Business Administration – 2000

Indiana University, B.S. in Finance – 1998

Previous Positions

LG&E – KU Services Company

2017 – current	Vice President of Gas Distribution
2013 – 2017	Vice President of Customer Services
2007 – 2013	Vice President of Energy Delivery – Retail Business
2003 – 2007	Director of Generation Services

Louisville Gas and Electric Company, Louisville, Kentucky

1998-2003	Maintenance Manager, Mill Creek
1996-1998	Manager Resource / Project Management, Louisville Gas and Electric - Fleet
1989-1996	Instrument and Electrical Supervisor, Mill Creek
1986-1989	Instrument and Electrical Technician, Mill Creek
1984- 1986	Production Operations, Mill Creek
1983- 1984	Coal Handling Operations, Cane Run
1980- 1983	Instrument and Electrical Technician, Cane Run

Other Professional Associations

Spalding University	2016 – current Board of Trustees
Louisville Orchestra	2016 – current President (elect) Board of Directors
	2012 – 2016 Executive Committee – Board of Directors
	2008 – 2012 Vice President of Development
LG&E Credit Union	2010 – current Chairman Emeritus
	2001 - 2010 Chairman and CEO, Board of Directors
	1998 - 2001 Treasurer, Board of Directors
	1995 - 1998 Board of Directors

Leadership Kentucky Board of Directors
2016 – current Board of Directors Executive Committee

2009 – 2016 Board of Directors

Catholic Education Foundation
2016 – current Board of Directors

Kentucky Association of Manufacturers
2016 – current Chairman – Board of Directors
2012 – 2016 Executive Committee – Board of Directors
2010 – 2012 Chairman of Energy / Natural Resources Policy Committee

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**)))))**	**CASE NO. 2016-00371**

REBUTTAL TESTIMONY OF
JOHN K. WOLFE
VICE PRESIDENT, ELECTRIC DISTRIBUTION OPERATIONS
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: April 10, 2017

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Q. Please state your name, position, and business address.

A. My name is John K. Wolfe. I am the Vice President of Electric Distribution Operations for Louisville Gas and Electric Company ("LG&E" or "Company") and Kentucky Utilities Company ("KU") (collectively "Companies"), and an employee of LG&E and KU Services Company, which provides services to LG&E and KU. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and work background.

A. I hold a bachelor's degree in mechanical engineering from the University of Louisville. I have been employed by the Companies in various capacities since 1991. I began as an engineer within LG&E's Gas Operations. I subsequently advanced through various management-level positions in Gas and Electric Distribution Operations – including group leader of Gas Engineering and Planning; manager of Gas Service Center; manager of Operations Center; director of Distribution Operations, and director of Electric System Restoration and Dispatch.

As a director, I participated in numerous electric industry committees on emergency preparedness, response, and mutual assistance, serving in various officer positions for the Southeastern Electric Exchange Mutual Assistance, Great Lakes Mutual Assistance, and Edison Electric Institute ("EEI") Mutual Assistance and Emergency Preparedness committees. I am currently vice chair of the EEI National Mutual Assistance Resource Team, which is responsible for assisting with resource allocation procedures during significant multi-regional or national emergencies involving the electric industry.

I have been Vice President of Electric Distribution Operations since March 2016. In this position, I am responsible for Electric Distribution and Transportation for the Companies, which includes Substation Construction and Maintenance, Substation Engineering, Distribution Operations, Design, Electric Reliability, Asset Information, Forestry Services, and Electric Engineering and Planning.

A complete statement of my work experience and education is attached as Appendix A.

Q. Have you previously testified before this Commission?

A. No. However, I have sponsored responses to requests for information to the Companies in this proceeding and in Case No. 2016-00370[1] and participated in and presented at various informal conferences involving show-cause proceedings.

Q. What is the purpose of your rebuttal testimony?

A. My testimony has two purposes. First, I will address the recommendation of Attorney General Witnesses Smith and Holloway to delay the installation of electronic reclosers as part of the proposed implementation of Distribution Automation ("DA") technology, for which the Companies seek a Certificate of Public Convenience and Necessity ("CPCN") in this case. My testimony demonstrates why such a delay would not serve any operational purpose or provide any benefit. Second, I will address the arguments of AT&T of Kentucky ("AT&T") and Kentucky Cable Television Association ("KCTA") regarding certain features of the proposed Pole and Structure Attachment ("PSA") Rate Schedule.

[1] *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and For Certificates of Public Convenience and Necessity*, Case No. 2016-00370 (Ky. PSC Nov. 23, 2016).

Distribution Automation

Q. Please explain how the components of DA work to improve system reliability.

A. DA implementation consists of two major components: installation of electronic reclosers on distribution circuits in need of improvement, and implementation of Distribution Supervisory Control and Data Acquisition (DSCADA) and Distribution Management System (DMS) technology. Reclosers are used on electric distribution systems to prevent transient short circuit conditions from creating prolonged power outages for customers, and to automatically restore power after momentary fault conditions clear. Reclosers by themselves (without DMS/DSCADA) are effective in improving circuit reliability through the use of manual switching.

DSCADA provides for automated and centralized data collection, monitoring and control of distribution system field devices, including reclosers, essentially automating historically manual processes. DMS provides for retention and complex real time analysis of data collected from field devices, enabling distribution system optimization based on the information obtained from field devices. In other words, the DSCADA and DMS systems are the "brains" of a distribution system, relying on massive amounts of data and providing decisional support that can greatly improve upon manual switching to minimize outage reach and duration.

Q. Is Mr. Holloway correct that installation of electronic reclosers is not beneficial until DMS and DSCADA are up and running?

A. Not at all. While electronic DSCADA-capable reclosers can be utilized effectively in conjunction with DSCADA and DMS to facilitate automated switching schemes, their independent use in producing reliability improvement is common in electric distribution systems. For example, the Companies' installation of 316 electronic reclosers not connected to DSCADA or DMS has played a significant role in reliability improvements on their electric distribution system since 2010. Furthermore, legacy hydraulic reclosers have been used in the electric industry and on the Companies' distribution system to improve reliability since the early 1940's.

Q. Why should the Companies install SCADA capable reclosers on DA program circuits prior to DSCADA and DMS implementation?

A. Circuits identified for DA program implementation have shown an existing need for reliability improvement and, as set forth above, reclosers in and of themselves will provide reliability improvement. Installation of reclosers on the highest priority DA circuits in advance of DSCADA and DMS availability will not only provide reliability improvements as soon as possible, it will also ensure that full DA benefits are available immediately on those circuits upon DSCADA and DMS implementation. Mr. Holloway's analogy - that installation of reclosers before full DSCADA and DMS implementation is like building the roof of the house before pouring the foundation - is inapt. Instead, it is more like installing a new HVAC unit on the house and then later installing a smart thermostat to run it automatically. Improvement is achieved immediately in the first phase, and full functionality is achieved in the second.

Q. If the Companies' proposed Advanced Metering System (AMS) were fully operational, would that help the Companies locate DSCADA-capable electronic reclosers as part of DA as Mr. Holloway suggests?

A. No. Whether operating independently or as part of an automated switching scheme, optimum recloser locations are determined through analysis of distribution system outage history, typically obtained from an Outage Management System (OMS), combined with distribution circuit characteristics and customer location information, typically obtained from a Geographic Information System (GIS). This combination of information allows calculation of potential reliability benefits for alternative recloser locations and thus identification of optimum recloser locations to maximize reliability benefits per dollar invested. Consistent with recognized industry practices, the Companies have utilized, and will continue to utilize, OMS and GIS to optimize recloser locations. Although AMS data has valuable applications in distribution system analysis, it doesn't significantly enhance the ability to optimize recloser placement for reliability improvement purposes.

Q. How is recloser installation timing reflected in the Distribution Automation (DA) program reliability improvement projections?

A. DA reliability improvement projections are based on recloser installations beginning at mid-year 2017 and continuing through 2022 and DSCADA and DMS completion in 2019. Reliability improvements projected from 2017 through 2018 are based on independent recloser operations with no connectivity to DSCADA. Reliability improvements projected from 2019 through 2022 are based on independent recloser operations combined with DSCADA and DMS facilitated automated switching.

Q. Can the Companies implement AMS and DA consistent with the proposed schedule?

A. Absolutely. Mr. Malloy has provided detailed testimony regarding the implementation of AMS so I will not speak to that. However, I can state that the Companies have developed human resource plans utilizing internal and external resources to ensure implementation of DA on the proposed schedule.

Q. In light of your testimony, how do you respond to the proposal of Mr. Holloway and Mr. Smith to delay the installation of electronic reclosers for two years?

A. There is no reason for any delay. Delaying installation of the electronic reclosers would simply delay reliability benefits that could be realized immediately by customers on the highest priority circuits. Once the DSCADA/DMS system is fully operational, customers on those circuits will immediately benefit from the full functionality of DA rather than wait further for the reclosers to be installed to realize any benefit at all. The delay proposed by Mr. Holloway and Mr. Smith serves no good or valid operational purpose. There should be no modification or adjustment to the implementation of DA, and the Companies respectfully request that the request for CPCN be approved.

Pole and Structure Attachment Rate Schedule

Q. Do AT&T and KCTA contest certain features of the proposed Pole and Structure Attachment ("PSA") Rate Schedule?

A Yes. AT&T contests the use of a tariff-based approach for structure attachments. AT&T and KCTA object to the calculation of the attachment rate for wireless facilities. AT&T and KCTA dispute the manner in which the PSA Rate Schedule addresses service drops. KCTA opposed certain terms and conditions in the PSA tariff.

Q. To place the issues raised by AT&T and KCTA into context, please briefly describe the Companies' provision of pole space.

A. The Companies operate approximately 487,192 utility distribution poles. The primary purpose of these poles is to support the more than 45,000 miles of wire and the other facilities necessary to provide electric service to more than 940,000 customers in the Companies' certified service territory. For much of their existence, the Companies have permitted others to attach their facilities to the Companies' poles for limited and specific purposes.

Local telephone companies were the first entities permitted to attach to their facilities to the Companies' utility poles. Like KU and LG&E, these entities held an exclusive right to serve a defined service area and required a network of utility poles to support the wires and other facilities necessary to provide that service. To reduce their cost of providing service and avoid the unnecessary duplication of utility pole networks, these local telephone companies and LG&E and KU entered joint use agreements to share the use of their utility poles. The local telephone companies were permitted to attach their facilities to the Companies' poles in exchange for the Companies receiving a similar right to attach to their facilities to the local telephone companies' utility poles. Under these agreements, the parties sought to maintain a roughly equal number of utility poles and to coordinate their utility pole construction.

In the 1950s cable television ("CATV") service providers, rather than constructing their own pole networks to support the cables and equipment necessary to provide CATV service, entered into agreements with the Companies to attach their equipment to unused space on the Companies' poles for a fee. Initially, these agreements were considered private contracts. In 1981, however, the Commission asserted jurisdiction over the provision of pole space to CATV service providers and required electric and telephone utilities to file with it rate schedules containing their rates, terms and conditions for such service.

With the onset of deregulation of the local exchange and inter-exchange telephone service in the late 1980s, entities seeking to provide local exchange service and long distance service. These providers entered into license agreements with the Companies for pole space for the facilities necessary to support such services. With the establishment and growth of the internet and the development of new forms of telecommunication services, the number of license agreements for use of pole space grew significantly. While the Commission noted the existence of such license agreements, it did not require that these license agreements be filed with it or rate schedules for such service be developed.

Recently, the Companies began receiving requests for pole space for the installation of pole-mounted small cell antenna. They have also received requests from governmental agencies for the installation of equipment necessary for the performance of specific governmental functions. In many of these instances, the Companies have provided pole space through private contracts that have not been filed with the Commission.

Currently, the Companies limit their provision of pole space to CATV service providers and telecommunication carriers. Pole space is not made available to private communication networks. With the exception of CATV service providers, none of these services are currently addressed in the Companies' filed rate schedules or in special contracts filed with the Commission.

Q. To understand the context of the operating issues raised by AT&T and KCTA, please, please briefly describe how attachments are organized and placed on a typical distribution pole.

A. A drawing best illustrates how facilities are organized and placed on a typical distribution pole. For the Commission's reference, I have attached to my testimony as Exhibit JKW-1 a drawing of a distribution pole with a pole top antenna.

The Companies' distribution poles are generally of three lengths: 35-foot, 40-foot and 45-foot. Each pole has a limited amount of pole space for attachments. Approximately six feet of the pole length is buried in the ground. The National Electrical Safety Code ("NESC") specifies certain vertical clearance standards for communication conductors such as telephone cables, coaxial and fiber cables. The standards will effectively govern how low an attachment may be placed on a pole. For example, a cable attached at the 18-foot level on a utility pole would not allow for mid-span sag in those places where the NESC demands 18 feet of ground clearance. The NESC clearance standard varies with the type of surface or structures over which the communications conductor hangs. The communications conductor must be placed high enough on the pole to enable the lowest point of the conductor's span between poles to achieve this clearance. The NESC minimum vertical ground clearance standards also apply to some types of ancillary equipment attached on the pole.

Except where an antenna is mounted on the pole top, the top of the typical distribution pole is reserved for electrical supply facilities. The primary conductor, the conductor that carries power from a substation to a pole-mounted stepdown transformer, is located above all other facilities on the pole. The voltage of this conductor, which is not insulated, is generally 7.2 kilovolts.

Where installed, the secondary conductor is located below the primary conductor. It provides the standard 3-wire single-phase 115/230-volt service for residential and small commercial customers. Though not shown on the diagram, in some instances a transformer may also be located on the pole and is used to stepdown the voltage from the primary conductor to the secondary conductor. Below the secondary conductor is the neutral - a single uninsulated grounded conductor whose purpose is to carry any unbalanced current to ground.

The area in which these electric supply conductors are located is considered "the power space." The NESC requires a 40-inch clearance between energized equipment and other facilities on the pole. The Companies' construction standards are stricter and require a 48-inch clearance. The lower clearance space that separates the electrical supply facilities from the communication facilities is labeled on Exhibit JKW-1 as "LG&E/KU Required Communication Worker Safety Zone" and is designed to provide adequate room for communication workers to maneuver safely while servicing the communication cables and to avoid contact with the electric supply conductors. As shown in Exhibit JKW-1, when an antenna is located on a pole top, an additional 48 inches of clearance is required to separate the lowest point of the antenna's mounting bracket from the electric supply conductors.

Various communication conductors and equipment may be located no closer than 48 inches below the lowest electrical supply conductor. These conductors include the various telephone, coaxial and fiber cables used to provide telephone, internet and CATV service. The minimum clearance distance at the pole between each communication conductor is 12 inches. In addition to attaching cables on the pole, CATV service providers and telecommunication carriers may attach additional facilities, such as radio equipment, to the pole.

In addition to attaching their facilities to a pole, Attachment customers may also connect these facilities to other facilities located on the pole or to facilities located at ground level. As shown in Exhibit JKW-1, a telecommunications carrier will connect its pole-top cell antenna to radio equipment also attached to the pole and to equipment located at ground level. To secure and protect the cables that connect this equipment, these cables are placed in conduit that runs vertically along the pole. Similarly, a telecommunications carrier may wish to connect its above ground cable attached to the pole with underground fiber cable and will require the use of conduit.

Use of Tariff-Based Approach for Attachments

Q. Do you have any comments regarding the contention of AT&T Witness Peters that the proposed PSA Rate Schedule should be rejected because "it would be more appropriate to retain the established contract-based approach, which has worked well for years and appropriately allows for differentiation between differently-situated attachers."

A. Yes. The contention ignores the history of the Commission's regulation of the provision of pole space and the changes that have occurred since 1981 in telecommunications industry and the regulation of that industry, including several recent Commission rulings and Commission Staff opinions.

KRS 278.040(2) provides that the Commission "shall have exclusive jurisdiction over the rates and service of utilities" and that this jurisdiction "shall extend to all utilities in this state." As defined in KRS 278.010(3), the term "utility" includes most entities that own facilities that provide electric or telephone service to the public for compensation. KRS 278.010(13) broadly defines "service" as "any practice or requirement in any way relating to the service of any utility."

In 1981 in Cases No. 8040[2] and No. 8090,[3] the Commission declared that providing space on utility poles for CATV pole attachments fell within the statutory definition of "service" and that "the rates, terms and conditions for providing such pole attachment space are within the jurisdiction of the Commission under KRS 278.010(12) and KRS 278.040."[4] The Commission further directed all utilities subject to its jurisdiction that provided pole attachment space for CATV systems to file tariffs "setting forth the rates, terms and conditions therefor."[5]

In its decision, the Commission noted that the use of space on utility poles had previously been a "subject of private negotiation and written agreements" between the utilities and CATV system operators. It further noted that some utilities urged the Commission to permit them to file pole attachment arrangements as "special contracts." Rejecting this approach, the Commission stated:

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[2] *The Regulation of Rates, Terms, and Conditions for the Provision of Pole Attachment Space to Cable Television Systems By Telephone Companies,* Case No. 8040 (Ky. PSC Aug. 26, 1981).

[3] *The Regulation of Rates, Terms, and Conditions for the Provision of Pole Attachment Space to Cable Television Systems By Electric Utilities,* Case No. 8090 (Ky. PSC Aug. 26, 1981).

[4] *Id.* at 11.

[5] *Id.*

> "[I]t seems preferable that the rates to be charged for CATV pole attachments, and the terms and conditions upon which the use is accomplished, be as uniform as possible throughout each utility's service area. Hence it is preferable that all regulated utilities providing, such pole space file tariffs for this service.[6]

The Commission also noted that, should special circumstances arise at some point that justified the different rates or conditions of service, the utility and pole attachment owner could use the special contract procedure.

At the time of the Commission's decision in 1981, the telecommunications industry was heavily regulated and the provision of local exchange and inter-exchange or toll service was a monopoly service. The internet at most was in an embryonic stage. CATV service providers were the only non-utility entities with a need to attach their facilities to utility poles. In subsequent years, however, the local exchange service was deregulated and the internet became a primary means of communication. As a result, local exchange service providers and internet service providers proliferated, increasing the number of entities that have sought to attach their facilities to the Company's structures.

Since 1981 the Commission has asserted jurisdiction over these other types of pole attachments. In Case No. 96-144, the Commission held that providing pole space for the attachments of non-CATV service providers and telecommunications carriers also fell within the definition of "service."[7] In 2005 the Commission expressly rejected arguments that its jurisdiction extended *only* to CATV attachments. In doing so, the Commission observed:

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[6] Case No. 8090, Order of Aug. 26, 1982 at 10-11.

[7] Case No. 96-144, *Laurel County Board of Education v. GTE South Inc.* (Ky. PSC Dec. 5, 1996).

> After reviewing the record, the applicable statutes and case law, we find it unquestionable that we have jurisdiction over pole attachments. The *Volz* Court unambiguously stated that the Commission "has jurisdiction over the utility companies, and that jurisdiction extends to their poles and the 'services' and 'rates' generated by pole attachment agreements." Any argument that the Court's decision in that case was limited to pole attachments of cable television operators fails in light of the Court's own interpretation of that decision in *Elec. & Water Plant Board v. South Central Bell Telephone Co.*, 805 S.W. 2d 141 (Ky. App. 1990).[8]

In Case No. 2009-00549, while finding that LG&E's CTAC Rate Schedule did not apply to the wireline attachments of telecommunication carriers, the Commission held that it possessed jurisdiction over the rates and conditions that the Company imposed on such attachments.[9] In each of these decisions, however, the Commission was silent on the applicability of KRS 278.160 to these non-CATV attachment agreements.

In a recently-published opinion, a copy of which is attached to my testimony as Exhibit JKW-2, Commission Staff asserted that the Commission's jurisdiction extended to wireless telecommunication attachments. In PSC Staff Opinion 2014-014, Commission Staff opined that "pole attachments, other than CATV attachments, are also a service, and are thus subject to Commission regulations regarding pole attachments" and that "as a service, the Commission possesses jurisdiction over the

[8] Case No. 2004-00036, *Ballard Rural Telephone Cooperative Corp. v. Jackson Purchase Energy Corp.* (Ky. PSC Mar. 23, 2005) (citations omitted) at 6.

[9] Case No. 2009-00549, *Application of Louisville Gas and Electric Company for An Adjustment of Electric and Gas Base Rates* (Ky. PSC Apr. 29, 2010).

rates and conditions that electric utilities impose for a wireless telecommunications carrier's attachments to the electric utilities' poles."[10]

In the same opinion, Commission Staff suggested that the provisions of the Companies' CTAC Rate Schedule apply to all attachments, including wireless telecommunication facilities:

> Commission Staff is unaware of specific evidence sufficient to support a claim that LG&E/KU's tariffs are unreasonable for use in connection with wireless telecommunications attachments. Therefore, with regard to whether or not LG&E/KU may negotiate contracts with the wireless telecommunications providers setting forth rates and conditions for use of pole space in lieu of establishing a rate schedule for such service, **Commission Staff concludes that existing tariff provisions of LG&E/KU apply to these attachments and separate agreements are not necessary**. . . .
>
> Likewise, **LG&E/KU tariffs contain provisions applicable to CATV attachments that Commission Staff believes to obviate the necessity of negotiated agreements.** Based upon your representation of the facts regarding wireless telecommunications attachments, it appears to Commission Staff that these tariff provisions would cover these attachments and the arrangements and costs between LG&E/KU and the wireless telecommunications providers.[11]

Q. Why are these developments important?

A. First and most importantly, the Commission through its orders and the opinions of its Staff has clearly indicated that providing space for any telecommunication facility, whether wired or wireless, is a service subject to Commission regulation. As such, it

[10] PSC Staff Opinion 2014-014 (Oct. 23, 2014) at 4.
[11] *Id.* (emphasis added).

is subject to the provisions of KRS Chapter 278, including KRS 278.160(1) which expressly provides:

> [E]ach utility shall file with the commission, within such time and in such form as the commission designates, **schedules showing all rates and conditions for service established by it and collected or enforced**. The utility shall keep copies of its schedules open to public inspection under such rules as the commission prescribes. [Emphasis added.]

Until PSC Staff Opinion 2014-014, however, neither the Commission nor its Staff had expressly stated that the rates and conditions of service for providing attachment space for non-CATV attachments were already subject to the existing filed rate schedules that governed CATV attachments. Given the above, the Companies believe it is appropriate to either modify their existing tariffs to address non-CATV attachments or develop new tariffs applicable to non-CATV attachments.

Secondly, AT&T cites out of context the Federal Communication Commission's ("FCC") preference for negotiated agreements between utilities and attaching entities.[12] The FCC's pole attachment regulation has *never* been tariffed-based for *any* type of attacher, it has always been complaint-based. The history of the Commission's regulation of the rates and conditions of service for pole space, however, clearly demonstrates that the Commission has chosen not to follow the FCC's regulatory approach.

Federal law generally vests the FCC with the authority to "regulate the rates, terms, and conditions for pole attachments to provide that such rates, terms, and

[12] Direct Testimony and Exhibits of Mark Peters at 4.

conditions are just and reasonable."[13] It, however, withholds such authority from the FCC in any case in which a state regulates the rates, terms, or conditions for pole attachments.[14] Federal law further requires a state that engages in such regulation to certify to the FCC that it does so.[15]

In the same 1981 Order in which it found pole attachments to be within the statutory definition of "service," the Commission certified to the FCC its jurisdiction over pole attachments.[16] In 1988, the Commission again certified to the FCC "that it has assumed jurisdiction over and regulates pole attachment rates, terms and conditions of jurisdictional utilities."[17] As recently as 2011, the FCC has identified Kentucky as a state that has asserted jurisdiction over pole attachments.[18]

After asserting jurisdiction over the provision of pole attachment space, the Commission rejected the FCC's methodology for establishing rates for such service and established a different methodology.[19] It further required that the rates and conditions of service for such service be tariffed-based, not contract based.[20] For the last 35 years, the Commission has continued to use this methodology notwithstanding its differences from the FCC's approach.

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[13] 47 U.S.C. § 224(b)(1).

[14] 47 U.S.C. § 224(c)(1).

[15] 47 U.S.C. § 224(c)(2).

[16] Case No. 8090, Order of Aug. 26, 1981 at 12.

[17] Kentucky Public Service Commission's Certification to Federal Communications Commission (Jan. 28, 1988) at 2, *available at* http://psc.ky.gov/order_vault/Orders_1980-1988/Orders_1988/19008040_01281988.pdf.

[18] *Implementation of Section 224 of the Act; A National Broadband Plan for Our Future,* WC Docket No. 07-245, GN Docket No. 09-51, Report and Order and Order on Reconsideration, 26 FCC Rcd 5240 (2011).

[19] Administrative Case No. 251, *The Adoption of a Standard Methodology for Establishing Rates for CATV Pole Attachments* (Ky. PSC Sep. 17, 1982) at 17.

[20] *See supra* text accompanying note 6. *See also*, *The CATV Pole Attachment Tariff of Kentucky Power Company*, Administrative Case No. 251-24 (Ky.PSC May 27, 1983).

Q. Would the PSA Rate Schedule remove flexibility for individual situations and impede the development of small cell telephone technology as AT&T Witness Peters asserts?

A. No. The use of a tariff-based system provides benefits to Attachment Customers and the Companies. First, the use of a tariff-based system eliminates the need for contract negotiations. The terms and condition for attaching are published and known to all members of the public. Neither the Companies nor Attachment Customers must incur the delay and expense of lengthy negotiations.

Second, the use of tariff-based system ensures that similarly-situated Attachment Customers are treated in a similar manner and that no customer receives an unreasonable preference or is subject to an unreasonable prejudice or disadvantage. It is consistent with the Commission's stated policy objective in Case No. 8090 that the terms and conditions for pole space be as uniform as possible throughout a utility's service area.[21]

Third, the special contract procedures set forth in 807 KAR 5:006, Section 13, provide additional flexibility to meet the unique needs of a customer or to accommodate different technologies or circumstances. Special contracts are intended to address unforeseen and unusual circumstances. The Commission noted as much when in Case No. 9764 it stated:

> Special contracts are indispensable for meeting the special needs of certain customers, where a proper

[21] *See supra* note 6.

> showing is made. A general tariff can never anticipate every set of circumstances that may arise.[22]

If exceptional circumstances exist that require arrangements differing from the terms of the proposed PSA Rate Schedule, the Companies will consider a special contract with the wireless Attachment Customer.[23] Should the Companies and a potential Attachment Customer be unable to negotiate a special contract, the Attachment Customer may file a complaint with the Commission pursuant to KRS 278.260 to seek service under terms that differ from the PSA Rate Schedule.

Fourth, the terms of the PSA Rate Schedule are not chiseled in stone. The PSA Rate Schedule can be amended to reflect changing technologies and industry conditions. Given that special contracts and proposed tariff revisions must undergo the same review process set forth in KRS 278.180 and KRS 278.190, AT&T's contention that use of a contract-based system in which all contracts will be filed with the Commission will avoid or reduce regulatory lag is dubious at best. It will take the same amount of time under either process. Under a tariff-based system, however, Attachment Customers have the opportunity to participate in the Commission review proceedings and to ensure that any approved tariff incorporates and reflects changes in technology and telecommunication industry practices and is fair and reasonable for all Attachment Customers.

During the 35 years in which the Companies' tariffs regarding pole attachments have been on file with the Commission, the Companies have sought to accommodate Attachment Customers whenever possible and to address any potential

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22 *Application of Columbia Gas of Kentucky Inc. and Toyota Motor Manufacturing, U.S.A., Inc. For Approval of Special Contract*, Case No. 9764 (Ky. PSC Feb. 12, 1987) at 11.

23 LG&E's Response to AT&T's Initial Set of Requests for Information, Item 8 (filed Jan. 25, 2017).

problems. They are not aware of any instances where the use of a tariff-based system impeded an Attachment Customer's use of its poles or limited the Customer's ability to employ new technologies.

Finally, AT&T has not demonstrated any significant differences in the contract-based system that it uses for attachments to its poles and promotes as the appropriate model and the tariff-based system that the Companies currently use for CATV attachments and propose to use for most telecommunication attachments. AT&T has a standard 39-page "stand-alone 21-state structure access agreement for poles, conduit and right of way" that it requires attaching customers to execute. While stating that it negotiates with its attachment customers, AT&T has not produced in response to discovery requests any contract that varies from the standard agreement. The contract appears to be a *de facto* tariff that contains all of the terms and conditions that AT&T uniformly imposes on its attachment customers.

Calculation of Attachment Rate for Wireless Facilities

Q. AT&T and KCTA have objected to the Companies' calculation of the proposed rate for wireless facility attachments. Please describe these objections.

A. AT&T contends that the Companies have allocated too much pole space to a wireless facility attachment in establishing the rate for such attachment. It contends that the appropriate amount of chargeable space for this type of attachment is one foot, not 11.585 feet as the Companies' calculations reflect. KCTA contends primarily that the Companies have not provided sufficient basis for the 11.585 feet used in the rate calculation. AT&T also contends that the Companies erred by assessing the same rate for pole-top and mid-pole wireless attachments.

Q. What is the Companies' response to these objections?

A. The calculations accurately reflect the space that is being used to enable the attachment of a wireless facility to the Companies' poles.

Under existing conditions, electric conductors are generally placed at the top of a utility pole allowing for maximum use of pole space. When pole-top attachments are located on a utility pole, however, the height of the utility pole must be increased by five feet to provide for adequate separation from the mounting for the wireless facility and the electric conductors. One-foot of this five-foot space is necessary for the mounting bracket for the wireless facility. The other four feet of space is necessary to provide the required clearance between the mounting bracket and the electric conductor. The Companies' longstanding construction standards require a 48-inch separation between electric conductors and communication facilities. This clearance standard is intended to protect the safety of the Companies' employees and contractors as well as that of communication company personnel.[24] It cannot be used by the Companies or any other user.

AT&T's argument that the 48-inch safety clearance space should be considered unusable space, and thus not allocated to the pole top wireless facility, ignores that the clearance space is there *solely* because of the placement of wireless facility. The additional five foot of pole space is necessary to place the wireless facility on the pole top. But for the location on the wireless facility on the pole top,

[24] This clearance standard is more stringent than that provided in the National Electrical Safety Code ("NESC"), which requires a clearance of only 40 inches. For purposes of allocating pole space, the difference in clearance distances is irrelevant. Utility poles are manufactured in a standard sizes. The Company cannot order a pole that is 52 inches taller than the existing pole to precisely comply with the NESC. The next size pole is five-feet longer. Hence five feet of pole space must be added to serve the Attachment Customer.

the additional space is not required and would not have been added; the additional five feet of space is solely for the benefit of the wireless facility. This is the case whether the additional five feet of space is deemed usable space or unusable space.

AT&T also incorrectly argues that the pole-top wireless facility should not be charged for pole space that the wireless facility's conduit uses. (The Companies calculate that the facility should be allocated 6.585 feet of usable space for this use.) AT&T asserts that this conduit does not preclude any other use of the pole. To the contrary, the conduit may prevent the Companies from installing transformers, risers, vertical supply conductors to aerial services, switch handles, capacitor banks or similar fixtures necessary for the provision of electric service to other customers. For this very reason, the Companies does not permit wireless facility attachments to wood poles supporting such facilities.

Q. Do the Companies agree with AT&T Witness Rhinehart that a taller pole costs less to operate?

A. No. Taller poles are more likely to encroach into the tree canopy and thus have higher maintenance costs. The Companies also incur a tax liability as a Contribution in Aid of Construction. Furthermore, the placement of a wireless facility on the pole top increases the difficulty and danger of maintaining the Companies' facilities on the poles. Company employees must take additional precautions to avoid the risks of radiofrequency radiation ("RF") which the wireless facilities emit and must also operate with greater care due to the presence of the wireless facility in the power space. Furthermore, the risk of damage to the Companies' electric facilities significantly increases due to the presence of facilities above the Companies' electrical conductors and other energized facilities. As KCTA Witness O'Loughlin has testified, attachments placed higher above grade place more stress and a greater amount of bending moment on a pole.[25]

Q. Do the Companies agree with AT&T Witness Rhinehart's assertion that mid-pole wireless attachments should be charged a different rate than pole-top attachments?

A. No. A separate rate for mid-pole wireless attachments is not practical at this time. The Companies expect almost all of the wireless facilities seeking pole space are likely to be pole-top facilities. The small number of mid-pole wireless facilities does not justify the development of a separate rate at this time.

Moreover, it is uncertain whether a wireless facility attached at mid-pole will require significantly less pole space to support a different rate. The clearance standards of the Companies and NESC are strictly vertical, which means that the necessary clearances must be maintained from the top and bottom of the antenna for mid-pole wireless attachments. There must be 48 inches from the top of the mid-pole to the Companies' electrical conductors and 12 inches from the bottom of the antenna or mounting hardware, which is lower, to the communications cable.[26] Assuming that the height of the antenna is 24-inches, the antenna will require an additional 36 inches of pole space. It will, therefore, be using five feet of pole space – the same amount of pole space allotted to wireless facilities placed at pole top.

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[25] Direct Testimony of Thomas J. O'Loughlin at 7.

[26] *See* Response of Kentucky Utilities Company to Kentucky Cable Telecommunications Association's First Request for Information, Item 16 (filed Jan. 25, 2017); Response of Louisville Gas and Electric Company to Kentucky Cable Telecommunications Association's First Request for Information, Item 16 (filed Jan. 25, 2017).

The Companies requested that AT&T provide the average height of its wireless facilities. AT&T has refused to provide this information and has suggested that the height of its facilities will vary.[27] In the absence of this information, there is simply no evidence to support a different rate for mid-pole wireless facility attachments.

Requirement for Load Bearing Study

Q. KCTA has objected to the PSA Rate Schedule requirements that each application for attachment include a load bearing study. Please explain the basis of KCTA's objection.

A. KCTA witnesses have testified that it is unreasonable to require analysis load bearing study with every application and that the Companies should require such analysis only if the Companies have a good faith belief that the addition of communications facilities will overload a pole.

Q. What is the Companies' response?

A. Prudent and good engineering practice requires that a load bearing study be conducted to ensure that the addition of the proposed attachment will not undermine the structural integrity of the utility. Furthermore, requiring a load bearing study is consistent with electric utility industry practice. Allowing a facility to be attached to a pole without such a study exposes public safety and service reliability to greater risk of pole failure.

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[27] AT&T's Responses to the Data Requests of Kentucky Utilities Company and Louisville Gas and Electric Company, Item 20 (filed Mar. 31, 2017).

Q. What is a load bearing study?

A. A load bearing study determines whether a proposed pole attachment can be accommodated without overloading the pole. The NESC requires that utility poles meet specified design criteria based upon calculated loads resulting primarily from wind and ice and the presence of attached facilities. The main risk associated with poles failing to meet these design criteria is that they may break or fail at wind or ice loads that are below the minimum design wind or ice loads for that geographic location, resulting in an increased risk to public safety and system reliability.

These specified design criteria are called "safety factors." The calculation of these safety factors is referred to as "pole loading." Among the inputs in these calculations are:

- pole class (size), length, wood species, age and groundline circumference;
- height, number, size, weight, type, angle, and span length of attached conductors and equipment;
- the height, number, and lead of guys supporting the pole and its attachments;
- height, number, size, weight, type, angle and span length of third party attachments, including cables, messenger wires, antennas and risers.

Some of this information may be obtained from a visual inspection of the pole. Some is based upon standard assumptions. The *LG&E Third Party Pole Attachment Handbook* provides several of the parameters that may be used to conduct the calculations.[28] This information is inputted into a computer software program that calculates the individual safety factors for a pole. The Companies use a software program called PoleForeman to conduct their load bearing studies.[29]

Q. Why is it important that a load bearing study be conducted for each application for pole space?

A. Load bearing studies are the primary means of mitigating the risk of pole failure due to overloaded poles. A utility pole failure can have severe consequences. A recent utility pole failure in Columbia, South Carolina left 22,000 customers without electric power.[30] In 2007 the failure of three overloaded wooden poles sparked the Malibu Canyon Fire that burned 3,836 acres, 36 vehicles, and 14 structures, including some historically significant structures.[31] The owners of the poles and the attachments to those poles were assessed over $63 million in penalties for placing attachments on poles that resulted in overloading the pole or failing to prevent the placement of those attachments.

Given such consequences, the requirement for a load bearing study for each new attachment to ensure that the Companies' utility poles are not beyond their load capacity is reasonable and prudent. It is also consistent with the Companies' obligations under Kentucky law. KRS 278.030(2) requires the Companies to "furnish adequate, efficient and reasonable service." KRS 278.042(2) requires electric utilities

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[28] Response of Louisville Gas and Electric Company to Kentucky Cable Telecommunications Association's First Requests for Information, Item 16, 9-25. While the Handbook applies only to LG&E operations generally, the load bearing assumptions are used for pole loading studies performed for KU poles and other structures.

[29] *Id.* at 27.

[30] *Many SCE&G Customers Regain Power After Utility Pole Failure*, ww.wltx.com, http://www.wltx.com/news/local/many-sceg-customers-regain-power-after-utility-pole-failure/309775352 (last visited Apr. 4, 2017).

[31] Melissa Caskey, *CPUC Approves $51.5-Million Malibu Canyon Fire Settlement*, Malibu Times (Sept. 19, 2013) http://www.malibutimes.com/news/article_3d62067a-2175-11e3-86b6-001a4bcf887a.html.

to construct and maintain its plant and facilities "in accordance with accepted engineering practices as set forth in . . . the most recent edition of the NESC."

In his testimony, KCTA Witness O'Loughlin acknowledges this very point:

> [P]ole loading analysis serves an important purpose in ensuring the safety and reliability of the electric distribution network. Utility poles are under strain, or load, as a result of a variety of factors, including the equipment placed on the pole, the forces applied to the pole, and environmental considerations like ice, wind pressure, and temperature. Pole loading assesses the horizontal and vertical tensions on a pole to determine if they are within the loading requirements and safety factors of the NESC. . . . The NESC requires utilities to design, construct, operate, and maintain all electric supply and communication lines in compliance with the rules and requirements of the NESC. Pole loading analyses are performed to insure these NESC requirements are met.[32]

In their testimonies, KCTA Witnesses Crone and O'Loughlin suggest that a load bearing study is not needed for every application because the Companies already have a detailed and exact understanding of the current load on their poles.[33] This is not the case. The Companies do not maintain a dynamic, real-time calculation of the load capacity for each of their 487,192 distribution poles. They do not maintain a current, up-to-date load bearing study to which they can readily reference. Prudence and good engineering practice require that any decision to permit the placement of an additional attachment be based upon current and accurate information about the pole to which the attachment will be made. The only means to obtain such information is through a load bearing study.

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[32] Direct Testimony of Thomas J. O'Loughlin at 3.

[33] *See, e.g.,* Direct Testimony of Thomas J. O'Loughlin at 3 ("when an attachment application is made, the utility can refer to the existing pole loading analysis and determine whether the structure can bear the attachment or further analysis is required for the attachment").

Requiring a load bearing study is no different than requiring a visual inspection to ascertain whether adequate clearance will exist for the proposed attachment. No one contends that the visual inspection is unreasonable. The load bearing study is simply attempting to obtain measurements that the human eye or a hot stick cannot detect.

The Commission has adopted a similar position, encouraging electric utilities to conduct load studies to prevent the occurrence of significant pole failures. In its "Ike and Ice: Report on the September 2008 Wind Storm and January 2009 Ice Storm," it found that "electric utilities, as pole-route owners, are responsible for ensuring the safety and integrity of their infrastructure. This includes evaluating the impact of attaching facilities to determine compliance with industry and regulatory standards."[34] The Commission recommended that "electric utilities conduct regular audits and inspections of pole routes to ensure continued compliance with applicable standards, including **evaluations of structure loadings** and facility clearances."[35]

Q. How long does it generally take to perform a load bearing analysis?

A. Based upon the Companies' own experiences, it takes approximately 30 minutes per pole to input the data and run the software program. The visual examination of the pole is not included in this time. However, an attachment application requires information, such as clearances, that can be obtained only through a site inspection. Therefore, an Attachment Customer must make visual examination of the pole as part of the application process even if no load bearing analysis is performed.

[34] Kentucky Public Service Commission, "Ike and Ice: Report on the September 2008 Wind Storm and January 2009 Ice Storm" (Nov. 19, 2009) at 92 (emphasis added).
[35] *Id.* 92-93 (emphasis added).

Q. What is your response to the statements of KCTA Witnesses Crone and O'Loughlin that the preparation time for a load bearing study is much longer?

A. Given each witness's failure to provide specific information on how he determined the time necessary to conduct a loading bearing study, the Commission should not give any weight to their testimony. Both witnesses were vague and non-specific in their statements regarding the time necessary to perform a loading bearing study. Mr. O'Loughlin stated "it generally takes an additional day for engineers to run pole loading."[36] He provided no quantitative support for his opinion nor did he state whether this estimate involve one pole or several hundred poles. He appeared to be discussing projects involving a large number of poles. Mr. Crone provided no estimate in his testimony.[37]

In a request for information, the Companies asked KCTA to state the amount of time generally required to perform a loading bearing study. On behalf of KCTA, Mr. Crone responded "15 days or longer."[38] Instead of providing a response related to the preparation of load bearing studies only, however, Mr. Crone provided an answer related to the time necessary to perform **all make ready analyse**s for an attachment application. No quantitative information was provided to support Mr. Crone's estimate.

Neither KCTA's witnesses nor its responses to requests for information indicate that any review of KCTA member records was made to develop an estimate

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36 Direct Testimony of Thomas J. O'Loughlin at 7.

37 Direct Testimony of Joseph H. Crone III at 5.

38 Kentucky Cable Telecommunications Association's Response to Kentucky Utilities Company Data Requests, Request No. 27 (filed Mar. 31, 2017); Kentucky Cable Telecommunications Association's Response to Louisville Gas and Electric Company Data Requests, Request No. 27 (filed Mar. 31, 2017).

based upon actual experience or that the estimates provided in their testimony were based upon hard number. Charter Communications, Mr. Crone's employer and a KCTA member, should have sufficient records to provide the average time necessary to conduct a loading bearing study. It provides CATV services on a nationwide basis. Since October 1, 2016, LG&E has required it to submit a loading bearing study with each pole attachment application.

In the absence of hard quantitative information, KCTA's claims regarding the time necessary to perform the studies should be afforded little, if any, weight. Regardless of the time necessary to perform the study, it still needs to be done to protect the public safety and ensure service reliability.

Q. What is the cost to perform a load bearing study?

A. The Companies recently queried some third party engineering firms to ascertain the cost of a loading bearing study. The responses indicated that the cost to perform a loading bearing study ranges between $40 and $100 per pole.

Q. What is your response to the assertion of KCTA's witnesses that the cost for a load bearing study is much greater?

A. KCTA's witnesses significantly overstate the cost of a load bearing study and offer no quantitative evidence to support their claims. The Commission should afford little weight to their claims.

First, KCTA's witnesses offered conflicting testimony as to the cost of a load bearing study. Mr. O'Loughlin stated that load bearing studies cost in the range of $1,000 per pole on the average.[39] Mr. Crone testified that the cost of a study was as

[39] Direct Testimony of Thomas J. O'Loughlin at 7.

much as $650 per pole.[40] Neither provided the basis for his estimate or indicated whether it was specific to a general geographical area. In response to a request for information, KCTA stated that Mr. Crone's estimate was not based upon any study, survey or document, but on his "decades of experience with pole loading."[41]

The actual experience of KCTA member Charter Communications conflicts with these estimates. In response to a request for information, KCTA stated that KCTA member Charter Communications' costs "**for make ready and pole loading studies** range from $300 to $900 per pole."[42] Despite the inclusion of costs for studies beside the load bearing study, the estimated range is well below Mr. O'Loughlin's estimate and generally below Mr. Crone's estimate.

Second, despite having information within its possession that would permit the Commission to determine the average cost of a load bearing study, KCTA refuses to share it with the Commission. In their requests for information, the Companies specifically requested that KCTA provide KCTA member Charter Communications' cost for **each pole loading study** performed as part of the application process to make an attachment to the Companies' poles. While acknowledging that it had performed such studies, KCTA refused to provide the cost of any individual load bearing study or an average cost of such studies. It provided only a range of costs and these costs were not segregate to allow the Commission to identify the actual cost of load bearing studies only. I can see no reason for KCTA's reluctance to provide this information if the information supports the assertions in its witnesses' testimony. That the

[40] Direct Testimony of Joseph H. Crone III at 5.

[41] Kentucky Cable Telecommunications Association's Response to Louisville Gas and Electric Company Data Requests, Requests No. 12 and No. 13 (filed Mar. 31, 2017).

[42] *Id.*, Request No. 15 (emphasis added).

information is not being provided suggests that the information does not support KCTA's claims.

Q. Does requiring an Attachment Customer to conduct its own load bearing study benefit the Attachment Customer?

A. Yes, in at least two respects. First, some electric utilities require the Attachment Customer to provide information about the proposed attachment and then will perform the load bearing study itself, assessing the cost to perform the study to the Attachment Customer. The PSA Rate Schedule gives greater control to the Attachment Customer in the selection of the firm performing the study and permits an Attachment Customer to foster competition among engineering firms and potentially lower the cost of such studies. Second, though sometimes the positions taken by KCTA make it appear otherwise, I presume KCTA members have a stake in the reliability of the pole network upon which they rely. The load bearing study requirement, as described above, further the pole network reliability and mitigates the risk of pole failure due to overloaded poles.

Q. What are the Companies' current practices for requiring the submission of load bearing analyses?

A. Since February 2015, the Companies have required telecommunication providers entering license agreements with them to submit a load bearing study with each attachment application. Since March 2016, LG&E has required all applications for pole attachments to submit a load bearing analysis with each attachment application. Charter Communications is among the Attachment Customers that have been subject to this requirement. Because of differences in its organizational structure, KU has been slower in implementing a similar requirement.

Q. Have the Companies received any complaints regarding their requirements for a load bearing study?

A. No. I am not aware of any complaints. While KCTA Witness Crone has raised several objections to the requirement for a load bearing study, his employer Charter Communications has not made any objections directly to the Companies since we implemented this requirement.

Q. Are the Companies' proposed requirements consistent with the electric utility industry's standard practices?

A. Yes. Load bearing analysis requirements are common practice across the electric utility industry. For example, Nashville Electric Service, PPL Electric Utilities and CPS Energy require applicants for pole space to provide a load bearing analysis with each application for attachment. AEP of Ohio, while not requiring an analysis with the application for pole space, required applicants to pay the cost of such analysis which it performs for each attachment.

Q. What is the Companies' response to KCTA Witness Crone's contention that the PSA Rate Schedule treats KCTA members in a different manner than joint users and wireless attachers by requiring a load bearing study?

A. First, the proposed PSA Rate Schedule does require all wireless attachers to perform a load bearing study. The requirement for a load bearing study applies equally to all Attachment Customers whether they are CATV operators, telecommunication carriers operating wireline facilities or telecommunication carriers operating wireless facilities. With the exception of those seeking to attach wireless facilities to the Companies' structures, all are treated in the same manner and are subject to the same requirements as they become subject to the PSA Rate Schedule. Those seeking to attach wireless facilities to the Companies' structures are subject to additional application requirements due to the nature of their proposed attachments. All, however, must submit a load bearing study with their application. In response to the Companies' requests for information, Mr. Crone has acknowledged as much.[43]

While Joint Users are expressly exempted from the PSA Rate Schedule, this action is consistent with prior Commission rulings that Joint Users have a legal status that differs from that of other types of Attachment Customers. In Administrative Case No. 251, the Commission found that this difference justified a different treatment for joint user:

> Considerable argument, and some evidence, was offered on behalf of the CATV operators that they have been treated unfairly by the utilities in not being accorded many of the rights granted each other by the utilities in their joint use arrangements. This issue is resolved by the decision of this Commission to treat CATV operators as customers of the utilities, with concomitant customer rights. CATV operators do not argue that they should be allowed to construct pole line systems of their own to share with the regulated utilities under typical joint use arrangements, and we see no reason why they should. Since they have no poles to "share," they need not be offered terms equivalent to

[43] Kentucky Cable Telecommunications Association's Response to Kentucky Utilities Company Data Requests, Request No. 3 (filed Mar. 31, 2017) ("KU's intention apparently is to require wireline and wireless facility Attachment Customers to perform a pole loading study as part of any application for attachment"); Kentucky Cable Telecommunications Association's Response to Louisville Gas and Electric Company Data Requests, Request No. 3 (filed Mar. 31, 2017) ("LG&E's intention apparently is to require wireline and wireless facility Attachment Customers to perform a pole loading study as part of any application for attachment").

> those in prevailing joint use agreements between utilities both of which own and share poles.[44]

Overlashing

Q. Describe the PSA Rate Schedule's requirements for overlashing.

A. The PSA Rate Schedule permits an Attachment customer to overlash a cable to its existing Attachments without such overlashing being considered a separate Attachment subject to an Attachment Charge and without written application if: (1) a load bearing analysis has been performed for such overlashing; (2) the overlashing is completed within 120 days of the Attachment over which the overlashing occurs, (3) no make-ready work of any kind is necessary to accommodate the overlashing; (4) a permit for the overlashing is obtained; and (5) written notice of the overlashing is provided to the Company within 30 days of completion. If these conditions are not met, the overlashing is considered a new Attachment for all purposes except the assessment of Attachment Charges.

Q. KCTA has voiced objections to the PSA Rate Schedule requirements for overlashing. Describe its objections.

A. KCTA contends these provisions are impractical and unreasonable. They argue that most overlashing occurs more than 120 days after the initial attachment and, as a result, the PSA Rate Schedule effectively subjects virtually all overlashing to the full-blown permit process. They further argue that because most overlashing involves lightweight fiber optic or coaxial cable, there is little risk that it will materially affect pole loading and thus there is no need for a load bearing study.

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44 *Supra* note 19 at 7.

Q. What is the Companies' Response?

A. KCTA assumes that the Companies have a detailed and exact understanding of the current load on their poles in real time and that the addition of a fiber optic or coaxial cable will not materially impact pole loading. As I testified earlier, the Companies have yet to develop such an informational capacity and must rely upon a load bearing study reflecting the most current conditions to ensure that a pole will not be overloaded. While overlashing may, as KCTA Witness O'Loughlin states, result in an increase of only five percent in pole loading, five percent is significant if the pole is at or near full capacity. Mr. O'Loughlin concedes that overlashing may have a materially impact on pole loading when the pole is near capacity.[45] The permitting requirement set forth in both the CTAC Rate Schedule and the PSA Rate Schedule are intended to prevent this occurrence.

Service Drops

Q. Describe how the PSA Rate Schedule addresses service drops.

A. Under the PSA Rate Schedule, a service drop is considered an Attachment for billing and permitting purposes if it (1) is attached to a pole without an existing Attachment; (2) extends more than one span along the trunk line (in which case each individual pole to which such Service Drop is attached shall be treated as the site of an individual Attachment), or (3) is not affixed to a pole within six (6) inches of Attachment Customer's existing Attachment.

The PSA Rate Schedule does not require an application for a service drop if (1) it is attached to a pole with an existing Attachment and is within six inches of that

[45] Direct Testimony of Thomas J. O'Loughlin at 17.

Attachment; (2) it conforms to all Company standards and all local, state, and federal laws governing its construction and attachment; and, (3) the Attachment Customer provides the Company with notice of the attachment by the end of the month following the attachment.

Q. KCTA and AT&T object to the manner in which the PSA Rate Schedule addresses service drops. Describe their objections.

A. KCTA and AT&T contend that the provisions are inconsistent with long-held practice that permitted the attachment of service drops without any applications or subsequent notice to the Company. They argue that requiring an application would significantly reduce their ability to quickly respond to customer requests for service. They further argue that as a service drop is light weight and would not materially affect the load on any distribution pole, it is unreasonable to require an application for attachment. Finally, as to the notice requirement, they contend that they lack a mechanism to monitor and report new service drops.

Q. What is the Companies' response?

A. Neither KCTA nor AT&T has shown in its testimony that the provision would actually affect its operations. In most circumstances, Attachment Customers would not be required to obtain prior permission before making a service drop attachment. Neither discusses how frequently it would actually be required to obtain the Companies' permission prior to attaching a service drop. Neither entity has offered any evidence to suggest the number of service drop installations that would be affected by the provision or that this number is so great that the ability of AT&T or any KCTA member to respond to customer requests for service would significantly suffer. The lack of such evidence suggests that under present conditions there are very few circumstances under which Attachment Customers would be required to obtain prior permission for a service drop.

The requirement that Attachment Customers notifying the Companies after making a service drop is necessary to ensure that the Companies have notice of new service drops meeting the stated conditions and can take steps to ensure that required safety clearances have been observed. It is not unreasonable for the Company to implement rules to ensure that it has notice of such attachments and can take actions necessary to protect service reliability and public safety. As noted in their responses to requests for information, the Companies have not intention to require no load bearing study for any service drop.[46]

As to their reported lack of adequate reporting systems, KCTA's members and AT&T currently have in place systems for billing their customers who receive service through those service drops in question. They apparently find it inconvenient to modify these systems to permit them to accurately and promptly report the placement of those service drops. For example, Mr. Crone offered the following explanation for Charter Communications' opposition to the required notice:

> Monthly reporting of new services drops is also not a practical or reasonable way to account for new drop attachments given that drop attachments are typically installed by service personnel rather than construction personnel who are responsible for the attachment permit process.[47]

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[46] *See, e.g.*, Response of Kentucky Utilities Company to Kentucky Cable Telecommunications Association's First Requests for Information, Item 15; Response of Louisville Gas and Electric Company to Kentucky Cable Telecommunications Association's First Requests for Information, Item 15.

[47] Direct Testimony of Joseph H. Crone III at 14.

Similarly, Mr. Early offered a similar explanation for AT&T's "inability" to report service drops:

> AT&T . . . has not developed a system for such reporting of these service drops to any entity's poles. To change the longstanding status quo and require applications or notice would require AT&T to establish a new procedure, just for KU and LG&E. Providing such reports would be administratively burdensome . . . [48]

It is not unreasonable to assume that these billing systems can be used to track the installation of new service drops or to expect KCTA members and AT&T to coordinate the efforts of their construction and service operations. Aside from an unsupported claim that compliance is not possible or too costly, neither entity has produced any evidence to support their claims of hardship. Their unsupported and unsubstantiated claims are not a sufficient basis to withhold approval from the PSA Rate Schedule.

<u>Strand-Mounted Wi-Fi Devices</u>

Q. What is the Companies' position regarding KCTA's assertion that PSA Rate Schedule's treatment of strand-mounted Wi-Fi devices is unreasonable?

A. KCTA's opposition appears to be based upon a misinterpretation of the Company's Response to KCTA First Request for Information No. 1-8. KCTA Witness Crone has erroneously asserted that strand-mounted Wi-Fi devices would be subject to the Companies' standard application and permit process. This is not the Companies' position.

[48] Direct Testimony of Kevin Early at 6-7.

Under the PSA Rate Schedule, strand-mounted Wi-Fi access points would be considered as an attachment and would be subject to the PSA Rate Schedule's provisions regarding construction and operation of attachments, including compliance with NESC clearance standards and prohibitions against interfering with the attachments of other Attachment Customers and impeding accessibility to LG&E's electrical facilities. However, as the strand mounted Wi-Fi access point would be considered as part of the wireline attachment, it would not be assessed a separate charge unless the strand itself required additional clearance as a result of the strand mounted Wi-Fi access point.

<u>Cost Reimbursement</u>

Q. KCTA objects to the provisions of the PSA Rate Schedule that require an Attachment Customer to reimburse the Company for various costs associated with the review of the Attachment Customer's application, the preparation of the Company's structures to receive the attachment. What is the Companies' response to these objections?

A. The cost reimbursement requirements set forth in the PSA Rate Schedule are not a departure from the requirements currently in the CTAC Rate Schedule and existing license agreements with telecommunication carriers. Sections 4, 5 and 8 of the CTAC Rate Schedule currently require Attachment Customers to reimburse the Company for various costs.

There is nothing unreasonable in requiring Attachment Customers to bear the costs that the Company incurs solely to enable the safe and responsible placement of those customers' attachments on the Company's structure. These costs are not associated with the provision of electric service. However, if the Attachment Customer were not assessed these costs, electric service customers would ultimately have to bear those costs.

Q. KCTA Witness Crone contends that the PSA Rate Schedule is unreasonable because it fails to require the Companies to provide the Attachment Customer with documentation to support their cost reimbursement claims. What documentation do the Companies provide when assessing charges?

A. KTCA's contention is erroneous. Each provision of the PSA Rate Schedule that requires an Attachment Customer to reimburse the Companies for the cost of certain services also requires the Companies to provide an invoice.[49] As a matter of practice, the Companies generally provide a cost estimate of any work that it will perform and requests the Attachment Customer's agreement before commencing such work. In those instances where an Attachment Customer finds the cost estimate is not in sufficient detail, it may request a more detailed invoice. The Companies engage in an informal process to resolve any questions or disputes about the charges billed for their work. I am not aware of an instance in which an Attachment Customer was refused an itemized statement. It is in the Companies' best interest to provide as much detail as the Attachment Customer desires to ensure prompt and timely reimbursement for the services provided.

The CTAC Rate Schedule, which currently governs CATV pole attachments, contains provisions similar to those found in the PSA Rate Schedule. It also requires the Companies to provide an invoice when seeking reimbursement for services

[49] The following Terms and Conditions of the PSA Rate Schedule require the issuance of an invoice: 6, 7b, 7e, 7f, 7g, 7j, 16, and 20.

provided. It does not specify the precise content of an invoice, but provides some flexibility to the Companies. In 2016 the Companies billed Mr. Crone's employer, Charter Communications, in excess of $400,000 for various services under the CTAC Rate Schedule. To my knowledge, Charter Communications did not object to any of the invoices for these services on the grounds that they lacked sufficient detail or information and paid the invoiced amounts.

Q. Does the PSA Rate Schedule contain a procedure for billing disputes?

A. No, it does not. Neither of the Companies' tariffs provides a procedure for billing disputes. The Companies, however, have internal practices and policies that encourage dispute resolution. To the extent that a formal process is necessary, 807 KAR 5:006, Section 10, provides such a process. If the Attachment Customer's concerns cannot be satisfactorily resolved, KRS 278.260 and 807 KAR 5:001, Sections 20 and 21 provide a means by which the Attachment Customer may bring its dispute to the Commission.

I believe the Companies have worked very diligently to resolve Attachment Customer inquiries. I am not aware of any significant disputes with Attachment Customers. I am not aware of any complaints filed with the Commission regarding the assessment of costs associated with the application process review or preparation work.

<u>**Denial of Access**</u>

Q. AT&T and KCTA witnesses have objected to PSA Rate Schedule Term and Condition 7c, which permits the Companies to deny access to a structure "based

upon lack of capacity, safety, reliability, engineering standards or other good reason." What is the Companies' response to these objections?

A. Both AT&T and KCTA agree that the Companies should have the right to deny access to a structure for lack of capacity, safety, reliability and engineering standards, but request that "other good reason" be stricken from the proposed PSA Rate Schedule. The Companies included this language to allow the discretion and flexibility to address unforeseen and unusual circumstances in which denial of access is in the best interests of the public. An Attachment Customer denied access under this section would have the right to challenge the denial by filing a Complaint with the Commission if it believed the denial of access was unreasonable, discriminatory or otherwise unlawful.

Q. Do the Companies object to the proposals of AT&T and KCTA to revise the phrase "future use" as the phrase is used in PSA Rate Schedule Term and Condition 8b?

A. Yes. AT&T and KCTA advocate removal of the term "future use" from the Term and Condition 8b and its replacement with language prohibiting the Companies from reserving any space on its poles for future use unless "such reservation is consistent with a bona fide development plan that reasonably and specifically projects a need for that space in the provision of its core utility service." They further request the Commission permit Attachment Customers to use space, with full knowledge of the timing of the development plan, until the Company actually needs it. In effect, AT&T and KCTA request that the Commission adopt the FCC's rules regarding reservation of pole space.

Please note that Term and Condition 8b deals with the construction and installation standards for Attachments, not the reservation of pole space. It provides:

> All Attachments shall be constructed and installed in a manner reasonable satisfactory to the Company and so as not to interfere with the Company's present or future use of its Structures. Attachments in Ducts shall not include any splice enclosures or excess cable. Attachment Customer shall maintain, operate and construct all Attachments in such manner as to ensure Company's full and free access to all Company facilities. All Attachments shall conform to the Company's electric design and construction standards and applicable requirements of the NESC, NEC, and all other applicable codes and laws. In the event of a conflict, the more stringent standard shall apply.

Term and Condition 8b contains no provision for the denial of pole space or the removal of existing attachments. It appears AT&T and KCTA's concerns actually involve Term and Condition 15, which permits the Companies to relocate or remove any Attachments if the space occupied by the Attachments is required in connection with the services that the Companies provide.

On this point, no revision to the PSA Rate Schedule is necessary. KRS 278.260 already establishes a standard for unreasonable denial of service and the means to obtain relief. Any Attachment Customer denied pole space because of the proposed use's effects on the Company's future use of that pole space may file a complaint with the Commission alleging an unreasonable denial of service. KRS 278.260(1) permits such complaints regarding service that "is unreasonable, unsafe, insufficient, or unjustly discriminatory . . . or is inadequate or cannot be obtained." The Company would be required to demonstrate the reasonableness of its denial of pole space.

As to AT&T's claim that the Companies could use the PSA Rate Schedule to restrict the use of its structures to further a plan unrelated to the Company's traditional electric utility service ("for example, to use the space for competitive communications service that would discriminate against attaching parties that provide such service and give electric utilities an unfair competitive advantage")[50], KRS 278.2213 would prohibit such conduct and any action of the part of the Company or its officials to engage in such conduct would subject them to possible civil and criminal penalties.

Insurance and Indemnity

Q. What is the Companies' position regarding AT&T's proposal that Attachment Customers be permitted to self-insure?

A. AT&T proposes that Attachment customers with a net worth in excess of $250 million be permitted the option of covering the risk of certain types of losses itself, rather than paying the cost to obtain insurance from a third party. The Company opposes the proposal for several reasons.

First, Rate Schedule CTAC, which currently applies to CATV pole attachments and which has been in effect in some form since 1984, historically required an attachment pole owner to maintain a certain level of insurance. The proposed PSA Rate schedule does not alter this requirement or increase the amount of current required insurance coverages. The requirement has served the Company well over the years with property and casualty claims.

[50] Direct Testimony and Exhibits of Mark Peters at 7-8.

Second, the proposal operates under the assumption that some Attachment Customers are “too big to fail.” Recent bankruptcies of such entities as WorldCom, Inc. (assets of $104 billion), General Motors Corporation (assets of $89 billion), Enron Corp. ($66 billion) and Lehman Brothers Holdings Inc. ($639 billion) disprove that assumption. Less than 10 years ago, Charter Communications, then the fourth largest CATV operator in the United States, sought and was granted protection under federal bankruptcy laws. As recent events have shown, the telecommunications industry is highly competitive and subject to significant fluctuation.

Third, the proposal would require the Companies to constantly monitor the net assets of the Attachment Customer to determine whether the Attachment Customer still qualified for self-insurance. Such a requirement would impose greater burden, expense and liabilities upon the Companies.

Fourth, while the present requirement for insurance coverage protects the Companies and their ratepayers from exposure to unreasonably risks, AT&T’s proposal would shift the exposure of risk to the Companies and their ratepayers. Insurance coverage remains outside the bankruptcy estate and provides protection to the Companies and their ratepayers regardless of the Attachment Customer’s status. If the Attachment Customer seeks protection under the bankruptcy laws, the assets that supposedly protect the Companies against any loss or adverse judgment would be shared with the Attachment Customer’s other creditors. As the cost of insurance is a cost of providing telecommunications service, it should remain a cost to the Attachment Customer and not be shifted to electric service customers.

Q. What is the Companies' position regarding AT&T's objections to the PSA Rate Schedule's indemnification provisions?

A. To the extent that AT&T objects to indemnification for claims arising out of the "joint negligence" of AT&T and the Company, its objection is contrary to Commission precedent. The Commission has on at several occasions specifically held that a utility pole owner "may require indemnification and hold harmless provision in cases of alleged sole or joint negligence by the CATV operator."[51] The PSA Schedule requires no more although it imposes that requirement on all Attachment Customers.

The Companies agree that they may not seek from an Attachment Customer indemnification for their sole negligence or willful misconduct. The Commission has previously declared that "to require indemnification by the CATV operator also against the sole negligence of the utility would offend the basic premise that the CATV is a customer of the utility."[52] The Commission, however, has also rejected that position that indemnification of pole owners should be limited to cases in which the Attachment Customers are at fault.[53]

---

[51] *The CATV Attachment Tariff of Fox Creek Rural Electric Cooperative*, Administrative Case No. 251-34 (Ky. PSC May 27, 1983) at 3; *The CATV Attachment Tariff of Grayson Rural Electric Cooperative*, Administrative Case No. 251-35 (Ky. PSC May 23, 1983) at 3; *The CATV Attachment Tariff of Green River Rural Electric Cooperative*, Administrative Case No. 251-36 (Ky. PSC May 9, 1983) at 3; *The CATV Attachment Tariff of Licking Valley Rural Electric Cooperative*, Administrative Case No. 251-42 (Ky. PSC May 12, 1983) at 2-3; *The CATV Attachment Tariff of Meade County Rural Electric Cooperative*, Administrative Case No. 251-43 (Ky. PSC May 9, 1983) at 2-3; *The CATV Attachment Tariff of Taylor County Rural Electric Cooperative*, Administrative Case No. 251-49 (Ky. PSC May 9, 1983) at 3.

[52] *The Adoption of a Standard Methodology for Establishing Rates for CATV Pole Attachments*, Administrative Case No. 251 (Ky. PSC Sep. 17, 1982), App. at 2.

[53] *Id.* ("to limit a CATV operator's indemnification to those cases in which the operator is at fault might unnecessarily increase the expense of the utility's insuring arrangements").

The indemnification provision in Term and Condition 17 recognizes that some claims against the Companies will arise solely from the presence of an attachment on the Companies' pole or work performed on those attachments. The potential for such claims represents additional risk and costs to the Companies that would not have otherwise existed but for the presence of the attachment on the Companies' pole. In the absence of any negligence or misconduct on the Companies' part, the claim should solely be the Attachment Customer's responsibility.

The Companies strongly disagree with AT&T's request that the Companies be required to indemnify Attachment Customers for claims arising out of their negligence or misconduct. AT&T has provided no support for its proposal. Furthermore, acceptance of such a proposal would likely increase the Companies' costs and the cost of service. The Companies are not required to indemnify other types of customers. To require them to indemnify Attachment Customers provides an unfair preference to those customers at the expense of other customers, many of whom lack the financial sophistication and resources that many Attachment Customers possess.

Q. KCTA has asserted that the PSA Rate Schedule's provisions regarding indemnification are unreasonable unless the Attachment Customer is permitted the right to select counsel to defend the claim and control the defense. What is the Companies' position?

A. They disagree with KCTA's proposal for two reasons. First, in this respect the requirement for indemnification set forth in PSA Rate Schedule does not differ from that found in current CTAC Rate Schedule. The CTAC Rate Schedule affords no right to the Attachment Customer to select defending counsel or to control the defense nor have any of the Company's prior rate schedules dealing with CATV attachments done so. Second, the Companies have a significant interest in the defense of any claim or action brought against it and involving the operation of its facilities. The Companies' reputation and the public's confidence in the Companies' operation of their facilities, two very valuable assets to the Companies, are at risk. It is not unreasonable, therefore, for the Companies to maintain control of the defense in civil actions.

<u>Other PSA Rate Schedule Provisions</u>

Q. What is the Companies' response to KCTA's objections to the tagging requirements set forth in the PSA Rate Schedule?

A. KCTA acknowledges that a tagging requirement for new and pre-existing facilities is reasonable and objects only to the application of a 180 day period to pre-existing facilities. The Companies have no objection to extending the time period for completing the tagging of pre-existing facilities. The Commission, however, should require the immediate tagging of all facilities installed after the effective date of the PSA Rate Schedule and should establish a specific time limit for completion of the tagging of pre-existing facilities. An open-ended period for pre-existing facilities, as KCTA proposes, is virtually unenforceable and readily invites Attachment Customers to ignore the requirement. Moreover, if the tagging period for pre-existing facilities is extended, the Commission should authorize the assessment of the same level of penalties that apply to unauthorized attachments for untagged facilities discovered after the end of that period. Such penalties would serve as an incentive for compliance.

Q. What is the Companies' position regarding KCTA's contention that the PSA Rate Schedule lacks a mechanism to address good faith billing disputes and will permit the Companies to remove attachments for such disputes?

A. The assertion is groundless. First, the proposed PSA Rate Schedule does not permit the Companies to remove attachments when a good faith billing dispute exists. Term and Condition 19 permits termination of the Attachment Agreement and remove attachments only if the "Attachment Customer fails to pay any undisputed fee required." It does not permit termination for a good faith billing dispute.

Second, KCTA has failed to cite any authority that a rate schedule must contain a provision for billing disputes. None of the Companies' current rate schedules have a dispute mechanism. Commission regulations, however, provide a mechanism to resolve customer disputes. 807 KAR 5:006, Section 10, provides a procedure for customer complaints. If the Company is unable to satisfactorily resolve the Attachment Customer's complaint, KRS 278.260 provides a means by which the Attachment Customer may bring its dispute to the Commission.

Finally, 807 KAR 5:006, Section 12, prohibits the termination of service where a good faith dispute over a bill exists. It provides:

> With respect to a billing dispute to which Section 11 of this administrative regulation does not apply, a customer account shall be considered to be current while the dispute is pending if the customer continues to make undisputed payments and stays current on subsequent bills.

No termination of service or removal of attachments can occur if a good faith dispute exists and the Attachment Customer is current on its undisputed bills.

Q. KCTA objects to bearing the cost of correcting "out of specification" conditions unless the PSA Rate Schedule contains a mechanism to identify the cause of the non-compliance. Do the Companies agree?

A. No. While acknowledging that Attachment Customers have an obligation "to correct problems with their own construction and maintain their facilities in compliance with applicable standards,"[54] KCTA argues that the Companies cannot require an Attachment Customer to correct out of specification conditions or pay the cost of such corrections unless the Companies demonstrate that the Attachment Customer caused the condition.

This position would place an unacceptable and unreasonable burden upon the Companies to determine the cause of an out of specification condition and adjudicate responsibility for the condition between various Attachment Customers. It would require the Companies to assume the role of investigator, prosecutor and judge – tasks for which the Companies are not readily suited and that would impose additional costs on electric service customers. As a practical matter, if the cause for out of specification condition cannot be easily identified, the utility pole owner will be forced to absorb the cost to correct the condition. In most cases, it will be difficult to prove "causation."

[54] Kentucky Cable Telecommunications Association's Response to Kentucky Utilities Company Data Requests, Request No. 9 (filed Mar. 31, 2017); Kentucky Cable Telecommunications Association's Response to Louisville Gas and Electric Company Data Requests, Request No. 9 (filed Mar. 31, 2017).

The most efficient means of addressing an Attachment's out of specification condition is to require the Attachment Owner to bring the Attachment into compliance. It is the Attachment Owner's property. It is the Attachment Owner who derives the most benefit from the Attachment's presence on the utility pole. As KCTA acknowledges, the Attachment owner has a legal and moral obligation to properly maintain its attachment. Furthermore, neither public safety nor service reliability can wait while an investigation into causation is conducted. Requiring the Attachment Owner to immediately repair its Attachment is the best means to protect the public.

If an Attachment Customer has reason to believe that the Companies or another attachment customer caused the out of specification condition, it may informally dispute the matter with the Companies and, if not satisfied with the result, bring the matter to the Commission's attention through the Commission's complaint process.

Q. What is the Companies' position regarding KCTA's contention that the PSA Rate Schedule unreasonably restricts the transfer of an Attachment Customer's rights?

A. KCTA incorrectly asserts that PSA Rate Schedule Term and Condition 4 would require an Attachment Customer to obtain Company approval of any "an internal restructuring or reorganization."

Term and Condition 4 provides: "Any delegation, transfer or assignment of any interest created by the Attachment Customer Agreement or this Schedule without Company's prior written consent is voidable at the Company's option." Under this term, the Company's consent is required only when legal title to the attachments is transferred to another legal entity. For example, if an Attachment Customer's corporate parent reorganizes or merges with another entity but the ownership of attachment remains with the Attachment Customer, then Company consent is not required for the merger or restructuring. The Company's only concern is that the owner of the attachments has an executed attachment agreement with the Company and has met the financial responsibility provisions of the PSA Rate Schedule. Moreover, should the Company unreasonably refusal to consent to a transfer of interest, the Attachment Customer and the acquiring party have bring a complaint with the Commission pursuant to KRS 278.260.

The restrictions on the assignment and transfer of attachment privileges found in Term and Condition 4 as virtually the same as those found Term and Condition 16 of the CTAC Rate Schedule. To my knowledge, Term and Condition 16 did not prevent Charter Communication's predecessors in interest from merging their business organizations nor did it require those entities to request the Companies' approval of their business reorganizations.

<u>Effects of AMS/DA Implementation on Attachment Customers</u>

Q. Briefly describe the anticipated effects of the Company's implementation of it proposed Advanced Metering System ("AMS") and Distribution Automation ("DA") Programs on Attachment Customers.

A. Contrary to KCTA's claims of that Attachment Customers will experience serious impacts and significant costs to remove, relocate and rearrange their facilities on

Company poles,[55] the deployment of the Companies' AMS and DA should have only a relatively small effect on Attachment customers. With regard to the DA program, the Companies are aggressively scouting locations for supervisory control and data acquisition system-connected reclosers that will not require the replacement of poles. These actions not only prevent Attachment Customers from incurring expenses related to the transfer of their facilities, but reduce the Companies' construction and program implementation costs.

As part of the DA Program, approximately 300 utility poles will be evaluated annually between July 2017 and December 2022 for electronic recloser installations. It is estimated that 50 to 75 percent of the poles evaluated will require replacement or relocation of facilities. These poles will be distributed across the LG&E and KU service territories. Based on this estimate, annual pole installations within LG&E and KU are projected to increase by two to three percent as a result of the DA program.

Attachment transfers to larger poles due to the AMS deployment are expected to be negligible.

Conclusion

Q. Do you have any recommendations for the Commission?

A. Yes. I recommend that the Commission disregard the recommendation of Attorney General Witnesses Smith and Holloway to delay the installation of electronic reclosers as part of the proposed implementation of DA technology, and grant the request for CPCN according to the Companies' proposed timeline. I further

[55] Direct Testimony of Joseph H. Crone III at 30.

recommend that the Commission approve the PSA Rate Schedule without modification.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John K. Wolfe**, being duly sworn, deposes and says he is the Vice President of Electric Distribution Operations for Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

____
JOHN K. WOLFE

Subscribed and sworn to before me, a Notary Public in and before said County and State, this ______ day of April 2017.

(SEAL)

____
Notary Public

My Commission Expires:

____

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John K. Wolfe**, being duly sworn, deposes and says that he is Vice President - Electric Distribution for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

John K. Wolfe

John K. Wolfe

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of April 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
~~My commission expires July 11, 2018~~
Notary ID # 512743

APPENDIX A

John K. Wolfe
Vice President, Electric Distribution
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-4312

Education

Bachelors in Mechanical Engineering, University of Louisville, May 1991
Graduate work in Mechanical Engineering, University of Louisville, 1991
Gas Distribution Engineering, Institute of Gas Technology, 1993
Graduate work in Business Administration, Bellarmine College, 1994-1995
E.ON Emerging Leaders Program, London Business School, 2003-2004

Professional Experience

LG&E and KU Services Company

Vice President, Electric Distribution	Jan. 2015 – Present
Director, Electric Sys. Restoration and Dist.	Feb. 2013 – Jan. 2015
Director, Operations	Nov. 2010 – Feb. 2013

E.ON U.S. LLC

Director, Operations	Mar. 2010 – Nov. 2010

Louisville Utilities Company

Manager, Operations Center	Feb. 2000 – Mar. 2010
Manager, Gas Service Center	Sep. 1997 – Feb. 2000
Group Leader Engineering and Planning	Jan. 1997 – Sep. 1997
Mechanical Engineer II	Sep. 1993 – Jan. 1997
Main Replacement Program Manager	May 1996 – Jan. 1997
Operations Auditor	Dec. 1994 – May 1996
Distribution Engineering	Sep. 1993 – Dec. 1994
Mechanical Engineer I	Jul. 1991 – Sep. 1993
Co-Op Student	Aug. 1989 - May 1991

Professional Memberships

American Society of Heating, Refrigerating and Air-Conditioning Engineers - 1991-1994
American Society of Mechanical Engineers - 1991-1994

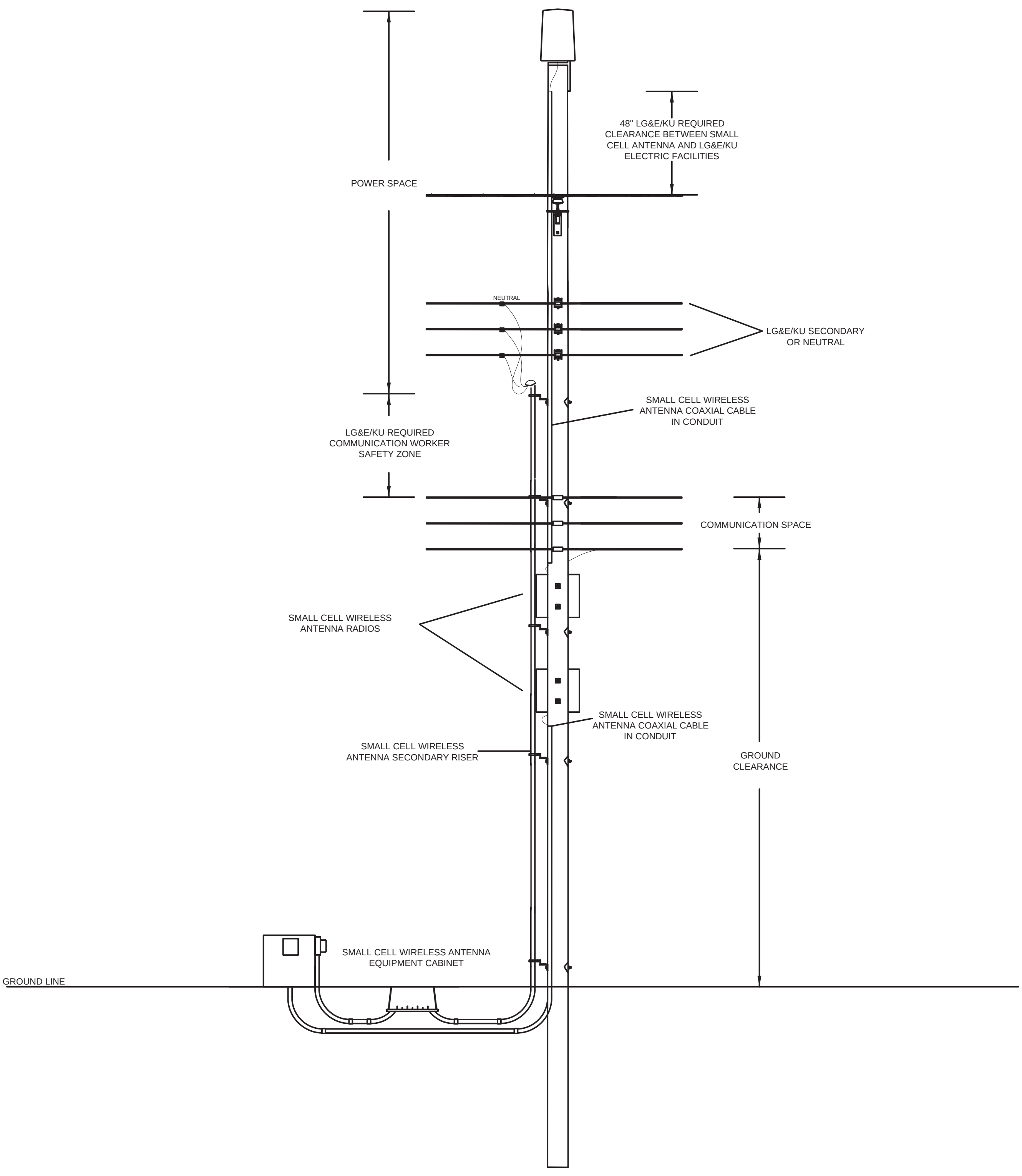
Civic Activities

Juvenile Diabetes Research Foundation Board of Directors - 2005-2008
Leadership Kentucky - Class of 2010
High School Athletics Coach - 2007-Present
Great Lakes Mutual Assistance Group Officer - 2013-2016
Southeastern Electric Exchange Mutual Assistance Officer - 2014-2016
Edison Electric Institute Mutual Assistance and Emergency Preparedness Officer - 2015-Present
National Mutual Assistance Resource Allocation Team Officer – 2014-Present
American Red Cross Board Member - 2016-Present
Southeastern Electric Exchange Board Member - 2016-Present

Rebuttal Exhibit JKW-1

Placement of Attachments on a Typical LG&E/KU Distribution Pole

1Ø POLE WITH ANTENNA ABOVE PRIMARY



Rebuttal Exhibit JKW-2

PSC Staff Opinion 2014-014

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Governor

Leonard K. Peters
Secretary
Energy and Environment Cabinet

Commonwealth of Kentucky
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David L. Armstrong
Chairman

James W. Gardner
Vice Chairman

Linda Breathitt
Commissioner

October 23, 2014

PSC STAFF OPINION 2014-014

Kendrick Riggs
2000 PNC Plaza
500 West Jefferson Street
Louisville, Kentucky 40202-2828

Re: Request for Legal Staff Opinion
An Electric Utility's Rental of Pole Space to Wireless Telecommunications Carriers

Dear Mr. Riggs:

Commission Staff acknowledges receipt your letter dated May 20, 2014, filed on behalf Louisville Gas and Electric Company (LG&E") and Kentucky Utilities Company ("KU"), requesting a staff advisory opinion to address an electric utility's rental of pole space to wireless telecommunications carriers. This opinion represents Commission Staff's interpretation of the law as applied to the facts presented, is advisory in nature, and is not binding on the Commission should the issues herein be formally presented for Commission resolution.

Specifically, LG&E/KY present the following questions:

1. Does the Commission possess jurisdiction over the rates and conditions that electric utilities impose for a wireless telecommunication carrier's use of space on the utilities' poles for wireless facility attachments?

2. When developing and negotiating any charges of fees and terms for a wireless telecommunications carrier's wireless facility attachments, may LG&E/KU adopt cost-based rates and conditions of service that reflect the unique characteristics of wireless telecommunications attachments?

3. May LG&E/KU negotiate contracts with the wireless telecommunications providers setting forth rates and conditions for use of pole space in lieu of establishing a rate schedule for such service?

You state that 47 U.S.C. § 224 generally requires a utility to make its distribution poles available to telecommunications carriers, which includes wireless carriers, whether providing voice or data communication. You further state that the Federal Communications Commission ("FCC") has held that 47 U.S.C. § 224 applies to wireless communications attachments.

You state that 47 U.S.C. § 224 does not apply in situations where a state regulates the rates, terms and conditions of pole attachments. You note that the Commission, in 1981, declared that providing space on a utility pole fell within the definition of "service" under KRS 278.020(13), was thus subject to Commission jurisdiction, and the Commission certified to the FCC its jurisdiction over pole attachments.[1] You also note that Kentucky Courts have affirmed the Commission's jurisdiction over these attachments as well as have expanded this jurisdiction to joint pole use agreements.

You state that when the Commission made its certification to the FCC in 1981, 47 U.S.C. § 224(f)(1) contained no reference to any "telecommunications carrier," which was only added when Congress amended the statute in 1996. You also state that the FCC, when adopting rules for wireless carrier attachments to electric poles, expressly made its rules applicable to states that have not asserted jurisdiction over pole attachments and identified Kentucky as a state that had asserted jurisdiction over pole attachments.[2] However, you note that the Commission's regulations refer only to cable and television ("CATV") pole attachments.

You state that the Commission, in Case No. 2004-00036[3], explicitly affirmed its jurisdiction over all attachments to Commission regulated utility poles. You also state that the Commission, in Case No. 2004-00036, stated that it would allow electric and telecommunications carriers to negotiate rates and conditions of pole attachments, and, absent an agreement, the Commission will determine the fair, just and reasonable rate to be charged.

You conclude that the attachment requested by the wireless telecommunications provider is a service under KRS 278.030. You request that Commission Staff: (1) confirm that LG&E/KU correctly interpret Case No. 2004-00036 to hold that the Commission exercises jurisdiction over the rates, terms, and conditions that an electric utility imposes for use of its pole space on wireless telecommunications attachments; (2) describe the extent of the Commission's jurisdiction in this area if Commission disagrees with LG&E/KU's interpretation of Case No. 2004-00036; (3) confirm that the

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[1] PSC Case No. 8040, *The Regulation of Rates, Terms and Conditions for the Provision of Pole Attachment Space to Cable Television Systems by Telephone Companies* (Ky. PSC Aug 26, 1981).

[2] *Implementation of Section 224 of the Act; A National Broadband Plan for Our Future*, WC Docket No. 07-245, GN Docket No. 09-51, Report and Order on Reconsideration, 26 FCC Rcd 5240 (2011). ("Section 224 Order").

[3] *Ballard Rural Telephone Cooperative Corp. v. Jackson Purchase Energy Corp.* (Ky. PSC Mar. 23, 2005.)

original 1981 certification to the FCC is necessary to inform the FCC that the Commission's original exercise of jurisdiction over pole attachments is not limited solely to CATV attachments and extends to all pole attachments; (4) confirm that the original 1981 certification of the Commission's exercise of jurisdiction over CATV attachments was sufficient to notify the FCC that the Commission exercised jurisdiction over all pole attachments, regardless of whether the definition of "pole attachment" was subsequently expanded or contracted.

You state that LG&E/KU believe that the differences between CATV attachments and wireless telecommunications attachments require that different rates and rules apply to wireless telecommunications attachments versus CATV attachments, and that the FCC has noted these differences. You state that LG&E/KU intend to develop rates for wireless telecommunications attachments that reflect the cost of providing the service, but that LG&E/KU believe that strict adherence to the rate methodology for CATV attachments is not appropriate and that a negotiated agreement would more accurately reflect the unique characteristics of wireless telecommunications attachments and would better serve the public interest. You request that Commission Staff opine as to whether or not it is appropriate for LG&E/KU, in negotiating and developing rates and conditions of service for wireless telecommunications attachments, LG&E/KU may adopt cost-based rates and conditions of service that reflect the unique characteristics of wireless telecommunications attachments.

You state that LG&E/KU maintain tariffs with the Commission that contain rates for CATV pole attachments, but none for wireless telecommunications attachments. LG&E/KU, because wireless attachments are a recent development, propose to address requests for attachments from wireless providers through the use of negotiated contracts.

Commission Staff, as discussed below, mostly agrees with LG&E/KU's interpretation of the Commission's jurisdiction over wireless telecommunications attachments.

You raise seven topics in your letter, three questions and four issues where you request Commission Staff to confirm LG&E/KU's interpretation of the state of Commission jurisdiction over pole attachments in general and wireless telecommunications attachments in particular.

As an initial matter, it is important to note that although most pole attachments are located below the pole owner's facilities and not on the top of the pole, the Commission has determined that the top of a pole is "usable space" for the purposes of pole attachments.[4] This designation is important because by being determined as "usable space," pole attachments made to the top of the pole are subject to the same Commission's regulation regarding pole attachments below the utility's lines.

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[4] Administrative Case No. 251, *The Adoption of a Standard Methodology for Establishing Rates for CATV Pole Attachments*, (Ky. PSC Sep 17, 1982) at 14.

With regard to your first question, "[d]oes the Commission possess jurisdiction over the rates and conditions that electric utilities impose for a wireless telecommunication carrier's use of space on the utilities' poles for wireless facility attachments . . .," Commission Staff answers in the affirmative.

In Case No. 2004-00036, the Commission determined that, except for attachments by or between local exchange companies and electric utilities, pole attachments, other than CATV attachments, are also a service, and are thus subject to Commission regulations regarding pole attachments. The Commission has even reached this conclusion regarding attachments that are not sought by public utilities.[5] Therefore, as a service, the Commission possesses jurisdiction over the rates and conditions that electric utilities impose for a wireless telecommunications carrier's attachments to the electric utilities' poles.

Wireless telecommunications attachments, because they would be attached above and below the utility's facilities on a pole, may require additional "make ready" work before being attached. However, Commission Staff is unaware of specific evidence sufficient to support a claim that LG&E/KU's tariffs are unreasonable for use in connection with wireless telecommunications attachments. Therefore, with regard to whether or not LG&E/KU may negotiate contracts with the wireless telecommunications providers setting forth rates and conditions for use of pole space in lieu of establishing a rate schedule for such service, Commission Staff concludes that existing tariff provisions of LG&E/KU apply to these attachments and separate agreements are not necessary. As discussed, supra, the Commission has determined that the top foot of a pole is "usable space" and should be made available for attachments. In making this determination, the Commission also included the top foot of the pole in establishing the methodology for determining rates for CATV attachments. Therefore, the per foot current rate that LG&E/KU charge for a CATV attachment would be the appropriate rate to charge for a wireless telecommunications attachment.

Likewise, LG&E/KU tariffs contain provisions applicable to CATV attachments that Commission Staff believes to obviate the necessity of negotiated agreements[6] Based upon your representation of the facts regarding wireless telecommunications attachments, it appears to Commission Staff that these tariff provisions would cover these attachments and the arrangements and costs between LG&E/KU and the wireless telecommunications providers. Commission Staff is of the opinion that if no agreement is reached regarding wireless telecommunications attachments, the wireless telecommunications provider seeking attachment may petition the Commission for relief, or, alternatively, LG&E/KU may file a revised tariff with cost support justifying its reasonableness.

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[5] *See* Case No. 96-144, *Laurel County Board of Education v. GTE South, Incorporated*, (Ky. PSC Dec. 5, 1996) at 2.

[6] *See* LG&E Tariff Electric P.S.C. No. 9, Original Sheet Nos. 40-40.7, KU Tariff P.S.C. No. 16. Original Sheet Nos. 40-40.7,

Regarding LG&E/KU's interpretation that the 1981 certification to the FCC was sufficient to inform the FCC that the Commission's exercise of jurisdiction is not limited solely to CATV attachments, Commission Staff cannot reach a conclusion over whether or not the FCC believes that this certification was sufficient to notify the FCC that the Commission's jurisdiction over pole attachments extended to all pole attachments regardless if the definition was expanded or contracted. Commission Staff notes, however, that the FCC, in its Section 224 Order, recognized that the Commission, among 20 other utility commissions, has certified that it regulates the "rates, terms, and conditions for pole attachments . . .."[7] In the Section 224 Order the FCC also states that, "[c]ertification by a state preempts the Commission from accepting pole attachment complaints . . .."[8] Perhaps this provides some indication as to the FCC's understanding regarding its jurisdiction over pole attachments in Kentucky.

This letter represents Commission Staff's interpretation of the law as applied to the facts presented. This opinion is advisory in nature and not binding on the Commission should the issues herein be formally presented for Commission resolution. Questions concerning this opinion should be directed to Staff Attorney J.E.B. Pinney at 502-782-2587 or at jeb.pinney@ky.gov.

Sincerely,

Jeff DeRouen
Executive Director

JEB/kg

[7] Appendix C to the Section 224 Order, *see also*, *States That Have Certified That They Regulate Pole Attachments*, DC Docket No. 10-101, Public Notice, 25 FCC Rcd 5541 (WCB 2010).

[8] *Id.*

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**)))))**	**CASE NO. 2016-00371**

REBUTTAL TESTIMONY OF
ROBERT M. CONROY
VICE PRESIDENT, STATE REGULATION AND RATES
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: April 10, 2017

Q. Please state your name, position, and business address.

A. My name is Robert M. Conroy. I am the Vice President of State Regulation and Rates for Louisville Gas and Electric Company ("LG&E" or "Company") and Kentucky Utilities Company ("KU") (collectively "Companies"), and an employee of LG&E and KU Services Company, which provides services to LG&E and KU. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What are the purposes of your rebuttal testimony?

A. The purposes of my testimony are to rebut various intervenors' arguments concerning cost recovery for the Companies' proposed Advanced Metering Systems ("AMS") full deployment, revenue allocation, residential Basic Service Charge and energy rate concerns, certain Curtailable Service Rider ("CSR") issues, several issues raised by the Kentucky School Boards Association ("KSBA"), low-income advocates' concerns, certain issues related to rates for Fort Knox, and several issues raised by Louisville/Jefferson County Metro Government ("Louisville Metro").

Q. Are you sponsoring any exhibits?

A. Yes, Rebuttal Exhibit RMC-1: Summary of Parties' Revenue Allocation Proposals.

AMS Cost-Recovery Proposals

Q. Several intervenor witnesses have recommended that AMS costs and benefits be addressed by various rate mechanisms or revenue-requirement adjustments, not standard ratemaking. Do you agree that AMS requires special ratemaking?

A. No. The purpose of standard ratemaking, which reflects the regulatory compact, is to design rates that allow a utility an opportunity—merely an opportunity—to recover its prudently incurred operating costs and earn a fair, just, and reasonable return on equity capital prudently deployed for utility purposes. It is ultimately the

Commission's role to determine if operating costs and capital deployments are prudent and therefore to be included in setting rates. But prudence is not clairvoyance; a prudence determination is necessarily an ex ante determination made under conditions of uncertainty based on what a reasonable utility manager knows or should know, not post hoc evaluations of what would have been better to do with the benefit of hindsight. Standard ratemaking accepts these fundamental points, as well as the reality that utilities' costs and revenues constantly change and never perfectly reflect what any test year suggested future costs and revenues might be. Therefore, standard ratemaking seeks to set rates based on the best information available at the time, acknowledging that a utility's actual future costs might be higher or lower, or its revenues higher or lower, than expected when rates were set.

But several of the intervenors in this proceeding seek to rewrite the regulatory compact with regard to a single cost item, namely the proposed AMS deployment. As I explain below with regard to each intervenor at issue, the intervenors' overarching proposal is largely or entirely to cap any rate exposure to the cost of the AMS deployment while guaranteeing customers receive credit for *at least* the full operational AMS benefits discussed in the AMS Business Case. Indeed, at least as described in the intervenors' testimony, customers could easily receive double the operational-savings benefits described in the AMS Business Case: once through benefit guarantee mechanisms, and again through actually reduced operating costs being reflected in future base rates. This "heads I win, tails you lose" approach is fundamentally at odds with the regulatory compact that has served Kentucky well for decades; the Commission should therefore reject all of the asymmetrical AMS-related rate proposals I describe below.

Q. Please describe how Attorney General witness Paul Alvarez recommends the Commission should "guarantee" customers receive certain benefits from the AMS Business Case.

A. Mr. Alvarez recommends the Commission require a ratemaking mechanism to guarantee benefits will be reflected in rates to the extents and within timeframes projected in the AMS Business Case.[1] He asserts benefit guarantees are necessary to overcome a utility's inherent disincentive to achieve promised benefits and efficiencies, including operating expense and non-technical loss reductions, until after the utility's next rate case.[2] Absent benefit guarantees, utilities can capture all the gains of AMS-related efficiencies, potentially indefinitely unless other circumstances require a utility to file a rate case. To alleviate this concern, Mr. Alvarez proposes a mechanism that would effectively reduce the Companies' revenue requirements each year of the AMS deployment to provide the Companies an incentive to achieve efficiencies and benefits of the magnitude and on the schedule set out in the AMS Business Case.[3]

Mr. Alvarez's benefit-guarantee mechanism would apply only to benefits that would otherwise redound to customers' benefit only through rate cases. To provide

[1] Alvarez at 38.
[2] *Id.* at 39-41.
[3] *Id.* at 42-44.

accountability for other benefits, he recommends having post-deployment oversight to ensure the Companies are working to deliver the benefits.[4]

Q. Do you agree the Commission should create a benefit guarantee for AMS of the kind Mr. Alvarez proposes?

A. Absolutely not. Mr. Alvarez's benefit-guarantee proposal does not address a vital question: Relative to what, precisely, does it guarantee benefits? For example, if the Companies achieve *any* AMS operational savings or non-technical loss benefits shown in the AMS Business Case, those benefits will be implicit in the Companies' test years in rate cases after full AMS deployment, and will be reflected in the Companies' Fuel Adjustment Clause charges or credits to the extent AMS reduces fuel costs or shifts fuel-cost recovery to responsible parties (via recovery of non-technical losses). But if the Companies are obliged to reduce their revenue requirements by prescribed amounts based on the AMS Business Case irrespective of whether they have achieved some, all, or more than the benefits reflected in the Companies' test years, the benefits will necessarily be double-counted and the Companies will be unable to earn a fair, just, and reasonable return on equity.

Perhaps Mr. Alvarez intended that his proposed benefit guarantee should be effective only until the first time new rates go into effect for the Companies following their next base rate cases; though Mr. Alvarez does not explicitly say this is his intent, it would have the benefit of avoiding the double-counting error. But if that is his intent, his proposed benefit guarantee is entirely unnecessary: The Company has included in the test year in this proceeding only a small portion of the total capital it

[4] *Id.* at 44.

will need to invest to complete the full AMS deployment, and therefore would likely need to file rate cases to account for the full AMS capital deployed. In addition, no significant AMS benefits are forecast until 2019, and full benefits do not arrive until 2020. Because the AMS is expected to be fully deployed by the end of 2019, it again seems reasonable to anticipate that the Companies might file rate cases to include full AMS capital in close proximity to when significant AMS benefits are anticipated to begin.

Moreover, the Commission, all intervenors, and the public are aware of Companies' AMS Business Case and the benefits underpinning it. The Commission would be well within its rights to open rate investigations for the Companies if it believed the Companies were indeed overearning due to AMS benefits not being reflected in base rates.

In sum, there are serious methodological problems with Mr. Alvarez's proposed AMS benefit guarantee, which seems to be a solution in search of a problem given the likely timing of the Companies' next base rate cases and the Commission's clear legal authority to open rate investigations for the Companies.

Q. What does Mr. Alvarez recommend regarding cost recovery for the AMS deployment, and what is your response?

A. Mr. Alvarez recommends requiring a mechanism to limit the Companies' recovery from customers of costs over those included in the AMS Business Case.[5] More particularly, he recommends a mechanism that would automatically disallow recovery

[5] Alvarez at 38.

of 50% of AMS cost overruns, though he admits he is not aware of any commission that has required such a mechanism for an AMS deployment.[6]

Such a mechanism is unnecessary. The Commission has clear authority to disallow imprudent capital and operating expenses. That the Commission can exercise that authority is not hypothetical, as the Companies are well aware from LG&E's experience concerning the disallowance of 25% of Trimble County Unit 1.[7] In addition, as noted above, the amount of AMS capital included for ratemaking purposes in this proceeding is small compared to the total proposed AMS investment; thus, if the Commission agrees the full deployment of AMS is prudent as proposed, certainly the small amount reflected in proposed base rates in this proceeding would be prudent and not represent any kind of cost overrun to be addressed by Mr. Alvarez's proposed mechanism or otherwise.

But the most significant concern with Mr. Alvarez's cost-overrun mechanism is precisely its apparently mechanistic nature; although Mr. Alvarez does not flesh out his proposal, it would appear to deem every cost beyond what the AMS Business Case contains to be simultaneously imprudent by half and prudent by half. In other words, his proposed mechanism would appear to obligate customers to pay for half of AMS cost overruns without Commission review while at the same time denying the Companies cost recovery for the other half without hearing or other Commission review.

[6] *Id.* at 45-46.
[7] *In the Matter of: A Formal Review of the Current Status of Trimble County Unit No. 1*, Case No. 9934, Order (July 1, 1988).

Given the concerns with Mr. Alvarez's cost-overrun proposal, it is not surprising no commission has approved it.

Q. What is Mr. Alvarez's proposal concerning carrying-cost recovery for assets retired as result of full AMS deployment, and why should the Commission reject it?

A. Mr. Alvarez argues the Commission should disallow recovery of any carrying cost for meters and other equipment retired early due to the AMS deployment.[8] His sole argument for this proposal is purely subjective; namely, in his view it would be unfair to ask customers to pay carrying costs for retired meters and currently deployed meters at the same time.[9]

But with all due respect to Mr. Alvarez's position, no party to this case has suggested that any part of the Companies' currently deployed metering infrastructure is imprudent. Were the Companies not proposing a full AMS deployment, there is no indication any participant in these cases would ask the Commission to disallow any metering cost. In other words, there is every indication—and it is certainly the Companies' position—that the Companies' currently deployed metering infrastructure, and therefore its carrying cost, is entirely prudent. The carrying cost of that infrastructure is therefore a necessary—not an optional—component of ratemaking in these proceedings.

The question before the Commission concerning the proposed AMS deployment is whether it will provide sufficient benefits relative to the Companies' already prudently deployed metering infrastructure to justify replacing that existing

[8] Alvarez at 46-47.
[9] *Id.*at 47.

infrastructure. If it is, and certainly the Companies believe they have shown it is, then deploying AMS would not render the existing and to-be-retired metering infrastructure imprudent; rather, AMS would be a prudent improvement to an already prudent set of metering investments. Therefore, there is no permissible ratemaking consideration that would justify Mr. Alvarez's position, which is based solely on what he believes is fair, and the Commission should reject it.

Q. Please summarize the position of KIUC witnesses Lane Kollen and Steven J. Baron concerning AMS cost recovery.

A. Mr. Kollen recommends not recovering AMS costs and passing benefits to customers through base rates, but rather implementing an AMS surcharge mechanism based on the Companies' ECR mechanisms.[10] The mechanism would allow recovery only of actual AMS costs, not budgeted amounts, and would cap the amounts eligible for recovery at the costs set out in the AMS Business Case.[11] He further recommends using a 5% depreciation rate for the assets in the mechanism's rate base to match the Companies' proposed 20-year AMS service life.[12] In addition, he asserts the costs to be recovered through the mechanism should be offset by operational savings and ePortal savings as set out in the AMS Business Case.[13]

Regarding the updating and allocation of the proposed AMS mechanism, Mr. Baron recommends updating Mr. Kollen's proposed AMS mechanism quarterly and allocating its cost on a per-meter basis rather than on a typical weighted customer basis because the Companies are not proposing to replace MV-90 meters as part of

[10] Kollen at 12-13.
[11] *Id.* at 13.
[12] *Id.* at 13.
[13] *Id.* at 13.

the AMS deployment.[14] He argues that because customers on Rates TOD-S, TOD-P, RTS and FLS nearly exclusive use MV-90 meters, those customers are unlikely to cause little, if any, AMS expense, and therefore should bear a relatively small share of the AMS cost.[15]

Q. How do the Companies' respond to KIUC's AMS cost-recovery proposals?

A. The KIUC's proposed AMS cost-recovery mechanism suffers from the same ratemaking infirmities as do Mr. Alvarez's asymmetrical benefit-guarantee and cost-overrun proposals; they violate the regulatory compact concerning the proposed benefit assurance and deprive the Companies and their customers of due process by prejudging as imprudent any and all AMS costs that exceed those set out in the AMS Business Case. Therefore, the Commission should reject the KIUC's mechanism proposal just as it should reject Mr. Alvarez's proposals.

Concerning Mr. Kollen's recommendation to use of a 5% depreciation rate for AMS, the Companies have already indicated they are willing to take the approach if the Commission believes it is appropriate.[16]

Finally, although it is correct that the Companies are not going to replace MV-90 meters during the AMS deployment, non-AMS customers will benefit nonetheless from enhanced operational efficiencies, reduced non-technical losses, and enhanced service restoration times. It is therefore appropriate for customers with MV-90 meters to bear some AMS costs, and the allocation Mr. Baron proposes would result in such customers bearing some AMS cost.

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[14] Baron at 40-41.
[15] Baron at 40-41.
[16] *See* response to LG&E AG 2-94.

Q. Please summarize the AMS cost-recovery position of Louisville Metro witness Jeffry Pollock.

A. Mr. Pollock asserts that each of the Companies is "reserving the right to flow additional costs associated with the AMS deployment to customers (i.e., the unrecovered cost of existing meters), [though] it is not similarly proposing any mechanism to flow any of the projected savings of the AMS deployment to customers."[17] Louisville Metro Councilman Kevin Kramer similarly asserts that LG&E is asking "the rate payer to cover the cost of equipment that will make it possible for LG&E to improve efficiency, without sharing the benefit of that efficiency which they paid for."[18]

Mr. Pollock's proposed solution to this alleged asymmetry is to reduce the revenue requirement for LG&E electric by $13.2 million and LG&E gas by $2.75 million to reflect the average annual operational savings from AMS for each utility shown in the AMS Business Case for calendar years 2019 and 2020.[19]

Q. Do you agree with Mr. Pollock's approach?

A. No. Mr. Pollock makes the same mistake Mr. Alvarez makes concerning existing metering infrastructure that will be retired due to the full AMS deployment: "[T]he unrecovered cost of existing meters" is not an "additional cost" of the AMS deployment precisely because the Companies will recover the prudently incurred costs of its existing metering infrastructure regardless of whether the Companies fully deploy AMS.

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[17] Pollock LG&E at 34-35.
[18] Kramer at 2:22-23.
[19] Pollock LG&E at 35.

To state it differently, the Commission will need to determine in this proceeding whether one possible state of the world, namely one without full AMS deployment, is more or less beneficial than another possible state of the world, namely one with full AMS deployment. But the regulatory compact requires that the Companies have the opportunity through rates to recover the cost (including carrying cost) of their existing metering plant in both possible future states of the world concerning AMS precisely because the cost of Companies' existing metering plant is a prudently incurred cost; thus, it is not an "additional cost" of full AMS deployment.

Therefore, the supposed "additional cost" on which Mr. Pollock seeks to justify his proposed revenue requirement reduction to account for imputed AMS benefits simply does not exist; there is no "additional cost" to customers of the kind he asserts, so he cannot use it to justify supposedly related benefits in the form of revenue requirement reductions. To do so would be a misuse of the matching principle (i.e., benefits should tie to the costs that create them) upon which Mr. Pollock ostensibly relies.

Mr. Pollock then further violates the matching principle by recommending the Commission impute into the current test year (July 2017 – June 2018) an average of AMS savings projected to occur in calendar years 2019 and 2020 without also imputing AMS costs from the same time period.[20] Stated simply, Mr. Pollock's proposal violates the matching principle, and the Commission should reject it as such.

[20] Pollock LG&E at 35.

<u>Revenue Allocation</u>

Q. Mr. Baron states he found an error in the data underlying the Companies' class cost-of-service studies in these proceedings that precludes using the studies to allocate the Companies' proposed revenue requirement.[21] How do the Companies respond?

A. As W. Steven Seelye discusses at greater length, Mr. Baron did identify a data error that affected the cost-of-service studies Mr. Seelye performed. There was no error in the cost-of-service studies per se. As Mr. Seelye notes in his rebuttal testimony, correcting for the error does not result in directional changes to the Companies' studies. Therefore, as Mr. Seelye further discusses, the Companies are not modifying their proposed revenue allocations.

Concerning the intervenors' proposed revenue allocations, it is noteworthy but unsurprising that each intervenor witness that addressed the issue in testimony advocated a revenue allocation that tended to be favorable to the intervenor for which the witness was testifying, as the attached Rebuttal Exhibit RMC-1 shows.[22] In contrast, the Companies' proposed revenue allocations attempted to move toward cost of service in a manner consistent with gradualism and without seeking to favor any particular customer or customer class.

I would further note that Mr. Baron's proposed revenue allocations contain an error, namely failing to reflect the position of Mr. Goins that the CSR credit should remain at the current level. To continue CSR credits at their current levels as Mr. Goins recommends requires additional revenue compared to the Company's CSR-

[21] Baron at 11-23.
[22] *See, e.g.,* Baron at 34; Pollock LG&E at Exh. JP-11.

credit proposal, and that additional revenue must be allocated across all customer classes, which Mr. Baron fails to do. The result is that his revenue allocations to all rate classes are understated relative to what they should be when correctly accounting for LG&E's need to recover from all customers the amount of the CSR credit Mr. Baron would like to retain. The columns under the heading "KIUC-Baron w/CSR and Uniform % Increase" in Rebuttal Exhibit RMC-1 correct this error; Mr. Baron's original allocation is in the "KIUC-Baron As Filed" columns.

Q. Do you have any comments concerning Mr. Pollock's revenue allocation proposals?

A. Yes. Mr. Pollock's proposed revenue allocations would result in markedly higher rate increases for LG&E's residential electric and gas customers than LG&E's proposed revenue allocations.[23] In particular, Mr. Pollock advocates allocating *all* of the proposed LG&E gas rate increase to residential customers.[24] These recommendations are clearly at odds with the testimony of the other witnesses for Louisville Metro. For example, Louisville City Councilman Bill Hollander states that one of the areas of "greatest concern [is] … the overwhelming increase to the Residential Class electric customer charge."[25] Councilman Kevin Kramer similarly states that one of the "greatest areas of concern [is] … the unwarranted increase to the Residential Class electric customer charge …."[26] Louisville Chief Financial Officer Daniel Frockt states his concern that an LG&E rate increase would increase bills for

[23] *See* Pollock LG&E Exhibits JP-11 and JP-15.
[24] *See* Pollock LG&E Exhibit JP-15.
[25] Hollander at 3.
[26] Kramer at 2.

residential customers receiving LIHEAP assistance.[27] If Louisville Metro is as concerned about residential bill increases as its testifying officials appear to be, it is odd and inconsistent for their rate expert to testify in favor of revenue allocations that would result in significantly higher residential rate increases that those LG&E proposed.

<u>Residential Basic Service Charge and Energy Rate Concerns</u>

Q. Several intervenor witnesses have argued the Company's proposed increases to residential Basic Service Charges will reduce incentives for energy efficiency,[28] make it more difficult for customers to reduce their bills,[29] and will hit hardest low-and fixed-income customers.[30] In addition, a number of customers have filed public comments, many as form letters, asking the Commission to reject the Company's Basic Service Charge proposal because, "It hurts people with low and moderate incomes," and makes it more difficult for customers to reduce their bills by reducing energy usage.[31] Do you agree?

A. No. LG&E's current residential energy charge is $0.08639 per kWh; its proposed charge is $0.08471 per kWh. For a customer using an average 957 kWh per month, that results in $1.61 per month of lower energy-consumption charges, and less than $19.50 per year. Therefore, if an LG&E residential customer were considering one or more energy-efficiency investments or behavior changes that would reduce the customer's average energy consumption by 20%—which would be a significant

[27] Frockt at 3-4.
[28] *See, e.g.*, Wallach LG&E at 11; Watkins LG&E at 52; Cummings at 9-10
[29] *See, e.g.*, Watkins LG&E at 52; Cummings at 9-10.
[30] *See, e.g.*, Cummings at 9-10; Hollander at 4; Kramer at 3.
[31] *See*, *e.g.*, Public Comment of Martina Kunnecke (Apr. 3, 2017).

energy reduction—the difference in the resulting savings under current rates versus proposed rates would be less than $4.00 per year. It seems unlikely that such a small change in bill savings would have any material impact on customers' incentives to reduce their energy usage solely for bill-reduction purposes or for conservation purposes.

Similarly, LG&E's current residential gas distribution cost component is $0.28693 per Ccf; its proposed charge is $0.25385 per Ccf. For a customer using an average 5.5 Mcf per month, that results in $1.82 per month of lower gas-consumption charges, and less than $22.00 per year. As with LG&E electric charges, it seems unlikely that amount of gas-charge reduction would have any material impact on customers' incentives to reduce their gas usage solely for bill-reduction purposes or for conservation purposes.

With regard to the assertion that low-income customers will be most affected by the increased Basic Service Charges, it appears the assertion is largely untrue. LG&E electric customers receiving third-party assistance in 2016 had an average consumption of 974 kWh per month, higher than the residential average of 957 kWh.[32] LG&E customers receiving WeCare in 2016 had an even higher monthly average consumption of 1,023 kWh.[33] Therefore, it appears that, on average, low-income LG&E customers will have lower bills under LG&E's proposed increased Basic Service Charge with lower kWh charges. For gas, customers receiving third-party assistance in 2016 had average monthly usage of 53.24 Ccf, slightly lower than

[32] Attachment to LG&E Response to ACM 1-3(a)(b).
[33] LG&E Response to MHC 1-22.

the average residential usage of 55 Ccf per month.[34] Therefore, it appears that low-income customers will, on the whole, be on average unaffected by LG&E's residential Basic Service Charge proposals relative to keeping the Basic Service Charges at lower levels and correspondingly increasing energy and gas consumption charges.

Notwithstanding that these intervenor assertions are meritless, they are also beside the point. As Mr. Seelye and I explained at length in our direct testimony and as Mr. Seelye addresses again in his rebuttal testimony, LG&E's residential Basic Service Charges are not designed or intended to promote or discourage energy efficiency or conservation, and certainly are not designed or intended to adversely affect low- or fixed-income customers; rather, they are designed to recover the customer-related fixed costs of providing service. Those costs simply do not vary with energy consumption, and it is therefore inappropriate to recover them through energy charges. Instead, because the costs are fixed, recovering the costs through fixed Basic Service Charges is appropriate. Moreover, as I showed above, increasing the Basic Service Charges as proposed will have almost no impact on customers' current conservation or energy-efficiency incentives, and will tend to be neutral or slightly beneficial to low-income customers on average.

Q. Jonathan Wallach, testifying for Sierra Club, asserts the Company's proposal to split the residential and Rate GS energy charges into infrastructure-related and variable components will confuse customers, and possibly erroneously suggests

[34] Attachment to LG&E Response to ACM 1-3(a)(b).

there is not a direct relationship between energy and demand for residential and GS customers.[35] Do you agree?

A. No. As Mr. Seelye discusses, providing customers, the Commission, and other stakeholders more information by splitting the residential and Rate GS energy charges into infrastructure-related and variable components will tend to educate all stakeholders about the underlying costs of the electrical service they buy. Indeed, it seems odd at best to suggest that keeping customers and other stakeholders in the dark is preferable to undertaking such educational efforts. Moreover, as Mr. Seelye further notes, splitting gas charges into commodity and delivery components for LG&E is both longstanding and Commission-ordered, and I am not aware of any customer-confusion issues arising from it.

Second, as the Company explained in discovery, there simply is not the direct relationship between energy and demand Mr. Wallach posits. It is entirely possible to have high demand in a month and relatively low energy usage. So the issue about which Mr. Wallach is concerned is illusory at best, and should not cause the Commission to reject the Company's proposal.

<u>Proposed Rate Increases and CSR Credit Decreases Are Separate and Independent Issues</u>

Q. Witnesses for KIUC and Mr. Pollock argue that the Companies' proposed rate increases coupled with the proposed reductions in CSR credits result in net bill increases for CSR participants that are excessive and do not comport with gradualism.[36] Do you agree?

[35] Wallach LG&E at 16-20.
[36] *See, e.g.*, Pollock LG&E at 53; Goins LG&E at 19; Simons at 3-4.

A. No. It is important to separate the issue of rate increases from the issue of how much all customers should be willing to pay for the right to curtail certain customers certain amounts under certain conditions, i.e., the level of CSR credits. Rate increases depend on revenue requirements and allocations of those revenue requirements among rate classes, largely by cost of service. That is a single, separable, and important issue in its own right, and it is the subject of most of these proceedings.

The issue of the appropriate CSR credit is entirely separate from other ratemaking considerations. As Messrs. Seelye and Sinclair address at length, setting CSR credits has *nothing to do* with CSR customers' utility bills and everything to do with what is an appropriate, reasonable price to pay CSR customers for the service they are offering. In that sense, namely as service providers, CSR customers are effectively vendors vis-à-vis setting CSR credits; they are selling a service—curtailment service—to the Companies and their customers. And though the Companies value highly the industrial customers who are also CSR customers, and therefore are keenly interested in the competitive concerns KIUC's customers have raised, the Companies owe a duty to all their customers to pay only what is appropriate and reasonable for CSR customers' willingness to curtail to various degrees under certain conditions.

Finally, I would note that, as Mr. Sinclair addresses in greater detail, CSR and non-firm service are not the same; rather, the Companies offer firm service and CSR credits for customers willing to curtail use under certain conditions.

Q. KIUC's witnesses, and particularly Dennis W. Goins, have requested "a Commission ordered, post-rate-case collaborative of stakeholders" to address CSR issues other than the value of CSR credits.[37] How do you respond?

A. The issues Mr. Goins suggests such a collaborative might address have all been the subject of rate-case settlement negotiations, with the possible exception of discussing genuinely interruptible service. Indeed, the current contours of the CSR rider are very much the product of those settlement discussions and negotiations. So the Companies, KIUC, and other intervenors have already had, and doubtless will have in the future, precisely the kinds of discussions in which Mr. Goins suggests a Commission-ordered post-case collaborative would have.

Moreover, a Commission order is not required for KIUC, its members, and the Companies to discuss these or any other issues. As Mr. Malloy notes in his rebuttal testimony, the Companies have Major Accounts Representatives whose sole task is to interact and exchange information with the Companies' largest customers, including KIUC's members. The Companies' personnel and KIUC's representatives also participate together in the Companies' DSM-EE Collaborative. Therefore, I do not believe there is a need for the Commission to order the Companies and KIUC to discuss these issues, and I further do not believe reporting to the Commission about such discussions is necessary.

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[37] Goins LG&E at 24-25.

KSBA Matters

Q. KSBA witness Ronald L. Willhite states that schools are different from other customers because of the statutory mandate contained in KRS 160.325.[38] Do you agree?

A. I agree that KRS 160.325 requires boards of education in Kentucky to "enroll in the Kentucky Energy Efficiency Program that is offered by the Kentucky Pollution Prevention Center at the University of Louisville in order to obtain information regarding the potential energy savings for every board-owned and board-operated facility."[39] That requirement does not apply to the Companies' other customers. But that requirement does not affect the cost of providing utility service to schools, and is not a basis for differentiating schools from other customers with similar service characteristics; rather, the statute intends to help boards of education and the schools they oversee develop plans to reduce utility costs. In that respect, schools are like most, if not all, customers, who presumably seek to reduce utility costs consistent with their need to use utility services. But certainly KRS 160.325, laudable as its aims may be, does not relieve the Companies of their statutory obligation to provide service on a non-discriminatory basis and to establish and maintain rate classes that ensure customers receiving "a like and contemporaneous service under the same or substantially the same conditions" will pay the same rates.[40]

Moreover, the General Assembly knows how to require special rate considerations for particular groups, including charitable or eleemosynary groups and

[38] Willhite LG&E at 4.
[39] KRS 160.325(1).
[40] KRS 278.170(1).

fire departments.[41] If the General Assembly has intended to create a special rate consideration for schools, it could easily have done so, but to date it has not.

Q. Mr. Willhite asks the Commission to require the Company to provide schools additional rate options.[42] Should the Commission accept that recommendation?

A. No. Over the course of more than a decade and multiple base-rate cases, the Companies have moved away from specialty rates to rate classes truly grounded in cost-of-service differences. In that same vein, the Companies have moved away from optional rates (except those offered on a pilot basis for the Companies to obtain data for possible future rate offerings) precisely because the Companies' goal has been to move toward cost-of-service-based rates. That philosophy and approach necessarily preclude optional rates; the cost to serve a customer is what it is, and ideally a utility's rates would collect exactly that cost. More practically, it is not possible to have perfectly tailored rates for each customer, so utilities use rate classes to group customers with similar service characteristics under the same rate structure and schedule. Therefore, even if a Rate P-12 Public School were justifiable as a separate rate class, the Company would not offer it as a rate option, but rather as the sole rate schedule appropriate for schools with certain service characteristics.

But as Mr. Seelye explains, contrary to Mr. Willhite's assertions, schools do not have unique service characteristics justifying school-only rate schedules. Therefore, the Commission should not require the Company to offer a school-specific Rate P-12 Public School, and certainly not as an optional rate, which would serve only to undermine the project of seeking to have all customers taking service under

[41] KRS 278.170(2) and (3).
[42] Willhite LG&E at 6-7.

appropriate cost-of-service-based rates, with each rate class separated by genuine cost-of-service differences.

Low-Income Advocates' Concerns

Q. Advocates for low-income customers have expressed concerns that the Company's proposed residential rate increase will be particularly challenging for low- and fixed-income customers.[43] How do you respond?

A. As I described at length in my direct testimony, the Company is aware of the difficulties low- and fixed-income customers face.[44] As a result, the Company has a number of programs in place to help customers with their bills and has proposed to maintain the existing HEA charge.[45] Also, the Company and its employees, customers, and shareholders have contributed considerable funds and volunteer work to aid low-income customers with their bills and to improve the energy-efficiency of those customers' residences.[46] In addition, the Company has a significant DSM-EE program designed exclusively to improve the energy efficiency of low-income customers' residences, and has undertaken special efforts to publicize that program.[47]

But the Company believes its rate request is necessary to continue providing safe and reliable service to all customers. Though the Commission has been clear that utilities cannot offer special rates to low-income customers,[48] the Company believes it has undertaken many, if not all, reasonable steps to provide aid to low-

[43] *See, e.g.*, Cummings at 9-10; Hinko at 4-5.
[44] Conroy LG&E at 58-62.
[45] *Id.*at 58-60.
[46] *Id.*
[47] *Id.* at 60-62.
[48] *In the Matter of Adjustment of the Rates of Kentucky-American Water Company*, Case No. 2004-00103, Order at 82-84 (Feb. 28, 2005).

income customers consistent with the Company's legal obligation of non-discrimination.

Finally, I would note again the recommendation of Mr. Pollock to increase residential rates more than what the Company has proposed.[49] In addition to being at odds with the professed concerns of Louisville Metro officials, it would place an increased burden on all residential customers, including low-income customers. Such customers and their advocates might inquire of their city representatives how seeking to increase residents' rates beyond what a utility requests is in the residents' interest.

Q. Cathy Hinko, testifying on behalf of Metro Housing Coalition, alleges that LG&E's proposed Basic Service Charge and Gas Line Tracker ("GLT") have disparate racial impacts.[50] How do you respond?

A. LG&E, as it both desire to do and is required to do under KRS 278.170, provides electric and gas service on a non-discriminatory basis. LG&E does not maintain data on the race of its customers, and would not do so even if it could. LG&E has plainly stated why it is seeking the Basic Service Charges and Gas Line Tracker rates it has proposed, and that is to ensure its rates better reflect LG&E's cost of service.

Q. Ms. Hinko asserts also that the proposed GLT changes cause renters rather than landlords to bear the cost of gas service lines, possibly in contravention of KRS 385.595. Do you agree?

A. No. As I explained in discovery in this proceeding, under LG&E's gas tariff, the Company—not the customer—owns the service line at the premises of residential

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[49] Pollock LG&E Exhs. JP-11 and JP-15.

[50] Hinko at 4-16.

customers.[51] KRS 383.595(1)(d) imposes on the landlord the duty to maintain in good and safe working order and condition certain facilities and appliances supplied or required to be supplied by the landlord. Natural gas service lines are not to be supplied or required to be supplied by the landlord, but instead are part of the Company's natural gas plant. Thus, KRS 383.595 does not apply to LG&E's proposed changes to the Gas Line Tracker.

<u>Issues related to Fort Knox</u>

Q. Thomas J. Prisco, testifying for the Department of Defense and All Other Federal Executive Agencies ("DoD-FEA"), states, "DoD would argued [sic] that if Fort Knox can produce electric power cheaper (for the installation), then LG&E's electric rates are not fair and reasonable."[52] Do you agree?

A. No. Whether a customer can economically self-generate relative to a utility's rates has nothing to do with whether the utility's rates are fair, just, and reasonable; rather, a utility's rates are fair, just, and reasonable when they permit the utility the opportunity to recover its prudent operating costs and a rate of return on capital sufficient to attract capital necessary to provide safe and reliable utility service. The definition of "fair, just, and reasonable" has no relationship to a customer's cost of self-generation.

Q. James T. Selecky, testifying for DoD-FEA, asserts that Time-of-Day Primary (Rate TODP) should have a provision for customers that have at least 1 MW of onsite generation to permit such customers to have one hour after an LG&E

[51] Louisville Gas and Electric Company, P.S.C. Gas No. 10, Original Sheet No. 97.3.
[52] Prisco at 7.

fault for the customers' generation to come back online before LG&E can set billing demands for the affected customers.[53] Do you agree with this proposal?

A. No. The underlying reason for a customer's demand does not affect the fact of the demand, and it is the fact of the demand, or more importantly the fact that the demand could occur, that causes LG&E to incur costs to build facilities of sufficient capacity to handle customers' demands, regardless of the demands' various causes. Therefore, from a pure cost-causation perspective, Mr. Selecky's proposal does not have support.

<u>Louisville Metro Concerns</u>

Q. Messrs. Hollander and Kramer testify that LG&E's currently proposed rate increase, coming after a recently implemented base-rate increase, is difficult for the city and its residents to absorb.[54] How do you respond?

A. LG&E appreciates that rate increases are challenging for customers, and therefore does not seek them lightly or without considerable forethought. But the evidence LG&E has supplied in this proceeding shows it will not earn a reasonable rate of return unless it is able to receive additional revenue. The additional revenue will allow LG&E to continue to provide the safe and reliable service LG&E's customers have come to expect, and indeed to enhance that service through the full AMS deployment and deployment of distribution automation, which will help ensure shorter outages and more reliable service.

[53] Selecky at 3, 13, and 17-19.
[54] Hollander at 3; Kramer at 3.

Q. Messrs. Hollander and Kramer note also that Louisville Metro have many streetlights, so LG&E's proposed lighting rate increases will disproportionately impact the city. Do you agree?

A. No. The reason for the increases to the lighting rates affecting Louisville Metro is precisely that those rates have historically been too low. Although LG&E understands a rate increase is never a welcome development, in the case of Louisville Metro's lighting rate increase, the magnitude of the increase is an indicator that the city has been receiving a relative bargain on those lights for a number of years.

Q. Geoff Hobin, testifying for Louisville Metro, notes that the demand charges associated with the Time-of-Day Secondary ("TODS") rate under which the Transit Authority of River City ("TARC") takes service for its electric buses cause the buses to be uneconomical compared to diesel-fueled buses.[55] Mr. Hobin therefore recommends "consideration of alternative, lower cost tariff options, or rate design proposals for electric vehicles operated for a public transit purpose,"[56] or, at a minimum, that "LG&E conduct electric vehicle load research, and … publish the results."[57] Do you agree with Mr. Hobin?

A. No. As Mr. Hobin notes in his testimony, LG&E has provided TARC two 500 kW transformers to support TARC's electric bus charging.[58] Those are significant transformers, and 500 kW is a significant demand, placing TARC's bus charging terminals squarely within Rate TODS. Mr. Hobin does not suggest that LG&E has

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[55] Hobin at 4.
[56] *Id.*
[57] *Id.* at 5.
[58] *Id.* at 2-3.

placed the charging terminals on an incorrect rate, and does not challenge the cost-of-service justification for the rates or rate structure of Rate TODS.

As Mr. Hobin acknowledges, the cost of electric service for massive 500 kW battery-charging stations is prohibitive relative to purchasing fuel for diesel-fueled buses, and TARC apparently desires to purchase more electric buses.[59] But Mr. Hobin does not state how an electric-bus-charging rate would be structured differently than Rate TODS while still reflecting the cost of serving electric bus charging stations; neither does he state how he believes conducting "electric vehicle load research, and … publish[ing] the results" would help develop a more advantageous rate that still reflects LG&E's cost of service. Indeed, Rate TODS has seasonal time-differentiated demand charges designed to reflect the differing costs of creating demand at different times of day, which reflect LG&E's load profile at different times of day across two seasons. It is not clear what having more data about bus charging would do to improve rate design from TARC's perspective.

Also, as I noted above concerning KSBA's arguments, over the course of more than a decade and multiple base-rate cases, LG&E has moved away from specialty rates to rate classes truly grounded in cost-of-service differences. In that same vein, LG&E has moved away from optional rates (except those offered on a pilot basis for the Companies to obtain data for possible future rate offerings) precisely because the Companies' goal has been to move toward cost-of-service-based rates. That philosophy and approach necessarily preclude optional rates; the cost to serve a customer is what it is, and ideally a utility's rates would collect exactly

[59] *Id.* at 4.

that cost. More practically, it is not possible to have perfectly tailored rates for each customer, so utilities use rate classes to group customers with similar service characteristics under the same rate structure and schedule. For TARC's bus charging, the appropriate cost-based rate is TODS. For these reasons, I do not believe either creating an electric-vehicle charging rate for public transit or conducting load research on charging electric buses is necessary or appropriate.

Q. Does this conclude your testimony?

A. Yes, it does.

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VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President – State Regulation and Rates for Louisville Gas and Electric Company and Kentucky Utilities Company, an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robt M. Conroy
Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of April 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

Rebuttal Exhibit RMC-1

Summary of Parties' Revenue Allocation Proposals

Louisville Gas and Electric Company
Summary of Parties' Revenue Allocation Proposals
Case No. 2016-00371

($000)	LOUISVILLE GAS & ELECTRIC COMPANY - ELECTRIC				AG - Watkins		KIUC-Baron As Filed		KIUC-Baron w/CSR and Uniform % Increase		Lou METRO - Pollock		KROGER-Townsend	
Rate Class	Total Revenue at Current Rates	Total Revenue at Proposed Rates	Change in Total Revenue	Percent Change in Total Revenue	Change in Total Revenue	Variance ($)	Change in Total Revenue	Variance ($)	Change in Total Revenue	Variance ($)	Change in Total Revenue	Variance ($)	Change in Total Revenue	Variance ($)
Residential Service	$ 441,462	$ 483,589	$ 42,126	9.54%	$ 42,126	$ -	$ 36,699	$ (5,428)	$ 37,467	$ (4,659)	$ 56,340	$ 14,214	$ 42,132	$ 5
Residential Time-of-Day Service	$ 56	$ 61	$ 5	9.53%	$ 5	$ -	$ 5	$ (1)	$ 5	$ (1)	$ -	$ (5)	$ -	$ (5)
General Service	$ 170,462	$ 182,642	$ 12,181	7.15%	$ 10,167	$ (2,014)	$ 14,170	$ 1,990	$ 14,467	$ 2,286	$ 8,408	$ (3,773)	$ 18,305	$ 6,124
Power Service-Secondary	$ 164,896	$ 176,527	$ 11,631	7.05%	$ 11,240	$ (391)	$ 13,708	$ 2,077	$ 13,995	$ 2,364	$ 8,551	$ (3,080)	$ 10,884	$ (747)
Power Service-Primary	$ 12,536	$ 13,571	$ 1,035	8.25%	$ 1,035	$ 0	$ 1,042	$ 8	$ 1,064	$ 29	$ 597	$ (438)	$ 1,356	$ 321
Time-of-Day Secondary Service	$ 84,439	$ 90,137	$ 5,698	6.75%	$ 4,677	$ (1,021)	$ 7,019	$ 1,321	$ 7,166	$ 1,468	$ 1,777	$ (3,921)	$ -	$ (5,698)
Time-of-Day Primary Service	$ 126,370	$ 136,756	$ 10,385	8.22%	$ 12,383	$ 1,998	$ 10,505	$ 120	$ 10,725	$ 340	$ 8,646	$ (1,739)	$ 10,385	$ (0)
Retail Transmission Service	$ 68,896	$ 74,720	$ 5,824	8.45%	$ 7,044	$ 1,220	$ 5,727	$ (97)	$ 5,847	$ 23	$ 4,472	$ (1,352)	$ 5,824	$ (0)
Fluctuating Load Service	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lighting Energy Service	$ 245	$ 245	$ -	0.00%	$ 21	$ 21	$ 20	$ 20	$ 21	$ 21	$ -	$ -	$ -	$ -
Traffic Energy Service	$ 304	$ 325	$ 21	6.76%	$ 18	$ (3)	$ 25	$ 5	$ 26	$ 5	$ 4	$ (17)	$ 21	$ -
Lighting Service & Restricted Lighting Service	$ 23,389	$ 25,310	$ 1,920	8.21%	$ 1,920	$ -	$ 1,944	$ 24	$ 1,985	$ 65	$ 1,852	$ (68)	$ 1,920	$ -
Curtailable Service Riders	$ (4,335)	$ (2,414)	$ 1,920	-44.30%	$ 1,920	$ -	$ -	$ (1,920)	$ -	$ (1,920)	$ 1,920	$ -	$ 1,920	$ -
Special Contracts	$ 10,275	$ 11,168	$ 893	8.69%	$ 1,084	$ 191	$ 854	$ (39)	$ 872	$ (21)	$ 1,074	$ 181	$ 893	$ -
Sales to Ultimate Consumers	$ 1,098,995	$ 1,192,635	$ 93,640	8.52%	$ 93,641	$ 1	$ 91,720	$ (1,920)	$ 93,640	$ 0	$ 93,641	$ 1	$ 93,640	$ 0

NOTE: Lou METRO Witness did not take a position on CSR in testimony.

($000)	LOUISVILLE GAS & ELECTRIC COMPANY - GAS				AG - Watkins		Lou METRO - Pollock	
Rate Class	Total Revenue at Current Rates	Total Revenue at Proposed Rates	Change in Total Revenue	Percent Change in Total Revenue	Change in Total Revenue	Variance ($)	Change in Total Revenue	Variance ($)
Residential Gas Service (RGS)	$ 214,164	$ 224,795	$ 10,631	4.96%	$ 9,831	$ (800)	$ 13,970	$ 3,339
Commercial Gas Service (CGS)	$ 90,228	$ 93,370	$ 3,142	3.48%	$ 3,504	$ 362	$ -	$ (3,142)
Industrial Gas Service (IGS)	$ 11,713	$ 11,713	$ 0	0.00%	$ 0	$ (0)	$ -	$ (0)
As Available Gas Service (AAGS)	$ 1,077	$ 1,005	$ (72)	-6.65%	$ -	$ 72	$ -	$ 72
Firm Transportation (FT)	$ 7,771	$ 7,927	$ 155	2.00%	$ 451	$ 296	$ -	$ (155)
Special Contract Intra-Company Sales	$ 2,922	$ 2,851	$ (71)	-2.43%	$ -	$ 71	$ -	$ 71
Distributed Generation Gas Service (DGGS)	$ 7	$ 8	$ 1	18.29%	$ 1	$ (0)	$ -	$ (1)
Substitute Gas Sales Service (SGSS)	$ 19	$ 61	$ 41	215.03%	$ 41	$ (0)	$ -	$ (41)
Sales to Ultimate Consumers	$ 327,902	$ 341,730	$ 13,829	4.22%	$ 13,829	$ 0	$ 13,970	$ 141

NOTE: Lou METRO Witness did not address DGGS, SGSS or Intra-Company Sales in testimony.

Rebuttal Exhibit RMC-1

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**)))))**	**CASE NO. 2016-00371**

REBUTTAL TESTIMONY OF
WILLIAM STEVEN SEELYE
MANAGING PARTNER
THE PRIME GROUP, LLC

Filed: April 10, 2017

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye. My business address is 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky 40014.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct testimony on November 23, 2016

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address class cost of service and rate design issues raised in the direct testimony of the following witnesses: Glenn A. Watkins on behalf of the Office of the Attorney General ("AG"); Stephen J. Baron on behalf of Kentucky Industrial Utility Customers, Inc. ("KIUC"); Dennis W. Goins on behalf of KIUC; Jeffry Pollock on behalf of Louisville/Jefferson County Metro Government ("Louisville Metro"); Neal Townsend on behalf of Kroger Co. ("Kroger"); Gregory W. Tillman on behalf of Wal-Mart Stores East, LP and Sam's East, Inc. ("Walmart"); James T. Selecky on behalf of the United States Department of Defense and all other Federal Executive Agencies ("DOD"); Thomas J. Prisco on behalf of DOD; Ronald L. Willhite on behalf of Kentucky School Boards Association ("KSBA"); Eric Wallin on behalf of JBS Swift & Company ("JBS Swift"); and Jonathan Wallach on behalf of Sierra Club and Amy Waters ("Sierra Club").

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction, (II) Electric Cost of Service Study, (III) Allocation of the Electric Revenue Increase, (IV) Electric Rate

Design, (V) Gas Cost of Service Study, (VI) Allocation of the Gas Revenue Increase, and (VII) Gas Rate Design.

II. ELECTRIC COST OF SERVICE STUDY

A. OVERVIEW OF THE POSITIONS OF THE PARTIES

Q. What is the purpose of a class cost of service study in developing rates for an electric utility?

A. The general purpose of a class cost of service study is to determine the cost of providing service for each of the major customer classes served by a utility for use in developing rates. As explained in the National Association of Regulatory Utility Commissioners ("NARUC") *Electric Utility Cost Allocation Manual*:

> Cost of service studies are among the basic tools of ratemaking. While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost of service standard, but it remains the primary criterion for the reasonableness of rates.[1]

More specifically, a cost of service study is used to attribute costs to each rate class based on how customers in the class cause costs to be incurred. A cost of service study is also used to identify costs that should be recovered through the various components of the utility's rates such as the basic service or customer charge, energy charge, and

[1] National Association of Regulatory Utility Commissioners ("NARUC") *Electric Utility Cost Allocation Manual* at p. 12.

demand charge.

Q. Is there general agreement among the intervenor witnesses on the purpose of a class cost of service study?

A. Yes, I believe that there is. All of the cost of service witnesses in this proceeding seem to acknowledge, perhaps to varying degrees, that the cost of providing service should be recognized in setting rates. However, the witnesses have different preferences for the methodology or methodologies that should be considered. In this proceeding, LG&E submitted cost of service studies using two different methodologies for allocating fixed production costs. In the first study, fixed production costs were time-differentiated and allocated using what has been referred to as the "modified BIP methodology". In the second study, fixed production costs were allocated using what has been referred as the "LOLP methodology". Some intervenor witnesses have expressed a preference for the modified BIP methodology while others have expressed a preference for the LOLP methodology. While the AG's witness prefers the modified BIP methodology to the LOLP methodology, his ultimate preference is for a methodology that he calls a "POD [Probability of Dispatch] methodology," which would effectively allocate more fixed production costs on the basis of the amount of energy used by each rate class as opposed to peak demands. KIUC's witness seems to have a preference for a single coincident peak (single CP) methodology.

Q. Please briefly describe the modified BIP methodology.

A. The modified BIP methodology was developed by LG&E in the early 1980s as part of a directive by the Kentucky Public Service Commission ("Commission") in

Administrative Case No. 203 for the major utilities in Kentucky to perform time-differentiated cost of service studies. "BIP" refers to Base-Intermediate-Peak fixed production costs. LG&E developed the modified BIP methodology because the standard BIP methodology did not produce reasonable results for a utility whose generation fleet consisted almost entirely of coal-fired base load power plants. With the traditional BIP approach, virtually all LG&E's generation assets would have been assigned as base costs and allocated on kWh despite significant seasonal variations in the Company's load.

The basic idea behind the modified BIP methodology was to assign a percentage of production capacity costs as "Base" or "Non-Time-Differentiated" based on the minimum amount of capacity that is required to provide service each and every hour of the year and then to assign the percentages of production capacity as "peak" and "intermediate" on the basis of the capacity required to serve the peak and intermediate periods. The modified BIP methodology therefore determines Base costs based on the relationship of the Company's minimum annual load to its maximum annual load. Intermediate costs are determined by first calculating the capacity represented by the relationship between the winter peak load to the maximum peak load and then allocating that capacity between the Winter Peak Period and the Summer Peak Period based on the hours in each of the winter and summer peak periods. The Summer Peak costs then represent the intermediate costs not allocated to the Winter Peak Period in the previous step, plus all remaining capacity.

In the modified BIP cost of service study, 34.38% of fixed production costs are considered Non-Time-Differentiated Costs and allocated on the basis of loss-adjusted energy (kWh); 36.02% of fixed production costs are categorized as Winter Peak Period Costs and allocated on the basis of winter coincident peak demand (i.e., class demand at the time of the winter system peak); and 29.60% of fixed production costs are categorized as Summer Peak Period Costs and allocated on the basis of summer coincident peak demand (i.e. class demand at the time of summer system peak).

Q. What are the points in favor of the modified BIP methodology?

A. The modified BIP methodology has at least three favorable attributes. First, with the modified BIP methodology, it is impossible for any customer class to get a free ride by not being allocated at least some fixed production costs. Because the Base or Non-Time-Differentiated costs are allocated on the basis of each class's annual loss-adjusted kWh energy, each class will necessarily receive an allocation of Base Costs. Therefore, even a hypothetical customer class that operates entirely off peak will still receive an allocation of Base costs.

Second, the modified BIP methodology gives consideration to the *utilization* of production capacity by all rate classes. With the modified BIP methodology, all rate classes that utilize the production system would receive an allocation of the production fixed costs even if any of the classes have zero on-peak loads. Therefore, the modified BIP methodology gives recognition to the *utilization* of the production facilities. However, a strong argument can be made that the *utilizatio*n of production facilities has little or no bearing on fixed production costs, particularly fixed costs of production facilities that have already been installed to meet customer demands.

Third, the modified BIP methodology has now been used for decades for both LG&E and KU, and almost four decades for LG&E. Thus, the continuity in the use of the modified BIP methodology must count as an important point in favor of the methodology.

Q. What criticisms of the modified BIP methodology have the intervenor witnesses made?

A. Witnesses for Louisville/Metro, KIUC and the DOD oppose the modified BIP methodology. Louisville/Metro witness Pollock makes the argument that "cost causation is primarily a function of peak demand".[2] He states:

> The reality is, as previously discussed, that the required amount of generation capacity is sized to meet a utility's peak demand. Further, an investment that is built to serve on-peak demand is also available to serve off-peak demand. In other words, off-peak usage is a bi-product of on-peak usage. Therefore, the BIP is not consistent with cost causation because off-peak usage is merely a bi-product of providing generation capacity that meets LG&E's projected peak demand.[3]

A criticism made by KIUC witness Baron is that the percentage cost assignments to the Base, Intermediate and Peak costing periods have changed over the years.[4] Certainly, the Companies' generation capacity needs have changed since the methodology was first developed. When the methodology was developed in the early 1980s, LG&E's generation system was planned to meet a high summer peak demand

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[2] Pollock testimony at page 45, line 14.
[3] *Id.* at lines 8-13.
[4] Baron testimony at page 25, lines 9-12.

and a significantly lower winter peak demand. With the merger of LG&E and KU, the Companies' generation capacity is now jointly planned and the combined systems now have a significant winter peak demand. While the Companies' summer peak demand is the principal driver in planning its generation capacity, the modified BIP methodology now allocates more costs to the winter peak period than to the summer peak period. Specifically, the modified BIP cost of service study allocates 36.02% of fixed production costs on the basis of winter coincident peak demand but only 29.60% on the basis of summer coincident peak demand. Mr. Baron states as follows:

> In this current 2016 case, the summer period is allocated the smallest share of costs, despite the fact that the combined Companies are strongly summer peaking during the projected test year (the summer peak is projected to be 11% higher than the winter peak).[5]

DOD witness Selecky offers three criticisms of the modified BIP methodology: (1) by using the modified BIP methodology, average demand is double counted in the allocation process; (2) that the modified BIP methodology fails to recognize tradeoffs between capital and operating costs; and (3) the modified BIP methodology is an oversimplification of the utility planning process.[6] Mr. Selecky goes on to explain that modified BIP methodology allocates too much fixed production costs to high load factor customers, e.g., customers that use significant amounts of power during off-peak periods.[7]

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[5] *Id.* at lines 1-4.
[6] Selecky testimony at page 9, lines 5-11.
[7] *Id.* at page 10, lines 5-7.

Q. Please briefly describe the LOLP methodology.

A. The LOLP methodology allocates fixed production costs on the basis of the load-weighted loss of load probability ("LOLP") for each hour of the test year. LOLP is a measure of the probability of the utility not having the resources to meet its demand in a particular hour. LOLP has been used for decades in the Companies' resource planning processes, and is a key measure for determining the Company's reserve margin requirements.

Q. What are the points in favor of the LOLP methodology?

A. The LOLP methodology allocates fixed production costs on the basis of a key planning metric used by the Companies. LOLP is a probability measure recognized in the industry as an important measurement for power production planning. Therefore, allocating fixed production costs on the basis of each rate class's contribution to the hourly LOLP ties cost allocation to the way that generation resources are planned. Also, the LOLP methodology does not allocate fixed production costs on the basis of customer load for a single hour of the year, as the single summer CP approach favored by Mr. Baron would.[8]

Q. What are the criticisms of the LOLP methodology?

A. Under the LOLP methodology, it would be theoretically possible for a particular rate class not to be allocated any production capacity costs. But as a practical matter, this does not occur on LG&E's system. The classes with the highest likelihood of this

[8] Baron testimony at page 30, lines 8-11.

occurring are street lighting rate classes. Because street lighting is used during nighttime hours, it would be possible for the class to have zero load during hours when there is a non-zero LOLP. However, this does not occur on LG&E and KU's systems. Using the LOLP methodology, all customer classes, including the lighting classes, are allocated some fixed production costs. Thus, the possibility of any rate class (such as for lighting service) receiving a free ride is merely theoretical. Unlike the single CP methodology favored by Mr. Baron, the LOLP would not create the situation in which particular rate classes would fail to be allocated some fixed production costs. Because street lights do not operate during the hour of LG&E and KU's summer system peak, the Companies' lighting rates would not be allocated any production capacity costs with the single summer CP methodology apparently favored by Mr. Baron.

Q. What are the intervenors' positions regarding the modified BIP methodology and the LOLP methodology?

A. While rejecting the LOLP methodology, the AG's witness, Mr. Watkins, finds the modified BIP methodology to be more acceptable, but he ultimately recommends a POD methodology. The AG's POD methodology will be discussed in greater detail later in my testimony.

KIUC's witness, Mr. Baron, seems to reject both methodologies. He states that the BIP methodology is flawed, yet he feels that details of the LOLP methodology have not been sufficiently reviewed. But DOD's witness Selecky comes to just the opposite conclusion, stating that, "LG&E witness Mr. Seelye discussed the LOLP methodology in detail in his prefiled direct testimony."[9] As indicated earlier, Mr. Baron seems to favor a single summer CP methodology. However, he does not present results for a single CP approach because of problems with the load data that he comments on, as will be discussed later in my testimony.

Louisville Metro's witness, Mr. Pollock, prefers the LOLP cost of service study to the modified BIP methodology. Mr. Pollock states:

> In my opinion, LOLP reflects cost causation. This is because LOLP recognizes LG&E's obligation to serve. The obligation to serve means that when customers flip the switch, the light or air conditioning will turn on and the machine will operate.[10]
>
> … In summary, cost causation is primarily a function of peak demand. Thus, a proper cost allocation method should emphasize peak demand. LOLP places more emphasis on peak demand. Therefore, it reflects cost causation.[11]

Mr. Pollock also states that the modified BIP methodology "is not consistent with cost causation because off-peak usage is merely a *bi-product* of providing generation capacity that meets LG&E's projected peak demand."[12]

Kroger's witness, Mr. Townsend, does not take a position on the two methodologies but seems to suggest that the class rates of return for the two studies should be averaged.[13]

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[9] Selecky testimony at page 11, lines 9-10.
[10] Pollock testimony at page 43, lines 15-17.
[11] Pollock testimony at page 45, lines 14-16.
[12] Pollock testimony at page 45, lines 11-13. Emphasis is in the original.
[13] Townsend testimony at page 9, lines 11-12.

Walmart's witness, Mr. Tillman, seems to prefer the LOLP methodology, or at least "does not oppose the use of the LOLP methodology."[14]

DOD's witness, Mr. Selecky, contends that it is more appropriate to use the LOLP methodology than the BIP methodology. Mr. Selecky states:

> [R]eviewing the development of the hourly LOLP allocators, it only takes approximately the top 50 peak hours when the loss of load probability is the greatest to develop the LOLP allocator. That is, after the 50 highest LOLP hours, the loss of load probability is so small it does not significantly contribute to the development of the allocator. As a result, the LOLP methodology gives much greater weight to the peak hours.[15]

Mr. Selecky's observation is important for two reasons. First, it underscores the point that the LOLP methodology gives greater weight to the peak load conditions on LG&E's system for which the Company's generation capacity is sized to meet. Second, Mr. Selecky's comment also underscores the fact that the LOLP methodology does not allocate the Company's entire generation assets on the basis of class loads during a single hour of the year, as the single summer CP approach favored by KIUC would.

Kentucky School Boards Association's witness, Mr. Willhite, prefers the LOLP cost of service study. Mr. Willhite states that the "LOLP Study is a more reasonable assessment of the relative rate of returns ('ROR') for each rate class."[16]

The positions of the intervenor witnesses can be summarized in the following

[14] Tillman testimony at page 17, lines 9-10.
[15] Selecky testimony at page 12, lines 3-8.
[16] Willhite testimony at page 5, lines 22-23.

table:

LOLP RECOMMENDED	BIP FAVORED	OTHER
Louisville Metro	AG -- BIP favored over LOLP but Probability of Dispatch (POD) recommended	KIUC – Single Summer CP
Department of Defense		AG – Probability of Dispatch Recommended
Walmart		Kroger – Average of LOLP and BIP
Ky School Boards Association		

TABLE 1

As can be seen from the above table, most of the intervenor witnesses favor the LOLP methodology.

B. ATTORNEY GENERAL'S POSITIONS ON CLASS COST OF SERVICE

Q. Please address the specific criticisms of the LOLP methodology made by the AG's witness.

A. The AG's witness, Mr. Watkins, puts forth three criticisms of the LOLP methodology. First, he claims that because the LOLP methodology was developed using proprietary software, the AG was not provided the source code and underlying algorithms. Second, he objects that because LG&E and KU currently have sufficient capacity to meet its load there are a limited number of hours for which the LOLP values are significantly greater than zero. Third, he claims that the Companies' LOLP methodology and calculations do not consider curtailable loads served under the Curtailable Service Rider.

Regarding Mr. Watkins' first criticism, the PROSYM model used by LG&E and KU to calculate the LOLPs is a longstanding and proven system planning software used in the electric utility industry. LG&E and KU have purchased a license from ABB to use the software. PROSYM is a standard model used by over 130 companies worldwide to evaluate production energy and reliability costs. PROSYM is a recognized model in the industry; the results of PROSYM are accepted by regulatory commissions all over the United States in the evaluation of utilities' integrated resource planning efforts. Furthermore, LG&E and KU have used PROSYM in their resource planning efforts for decades. While LG&E and KU would not be permitted to provide the source code or algorithms used by ABB in PROSYM, nor do the Companies have the source code, ABB's technical sheets on PROSYSM's LOLP algorithms were provided response to LG&E AG 1-293, which was subject to a non-disclosure agreement that the AG's witness signed. Additionally, the AG could have requested on-site visits to verify the reasonableness of the LOLP calculations or requested independent information from the PROSYM vendor. Furthermore, as discussed in the response and in the attachments to LG&E Metro 2-4, the Companies validated the reasonableness of PROSYM's LOLP model results using an Excel model.

With respect to Mr. Watkins' second criticism, while it is correct that LG&E and KU currently have sufficient generation capacity to meet customer demands on their systems, Mr. Watkins misses the entire point of the LOLP procedure used by the

Companies. Regardless of whether LG&E and KU currently have sufficient capacity to meet their demands, for decades it has been the loads for a finite number of hours that drive the Companies' need for new generation capacity. For most hours of the year, the LOLP values have always been low. For decades, the Companies' generation additions have been driven by loads during LG&E and KU's summer and winter peak periods. The purpose of the LOLP methodology is to identify the hours during the year that have the highest likelihood of the Companies having unserved demand. LG&E and KU's generation assets must be sized adequately to meet these critical hours. Therefore, these high-load hours of the year drive the amount of generation capacity that the Companies must have to meet the needs of customers. This is the point that the DOD's witness Selecky comments on but which the AG's witness fails to recognize. The DOD witness observed correctly that the LOLP cost of service study allocates fixed production costs predominantly on class loads for the 50 hours of the year with the highest LOLP values. Obviously, the system load during these hours of the year drive the amount of generation capacity that the Companies must install. LOLP also drives reserve margins used by LG&E and KU for resource planning.

Mr. Watkins is incorrect in his claim that the Companies' LOLP methodology and calculations do not consider curtailable loads served under the Curtailable Service Rider. The Company does consider the curtailable load in the LOLP calculations, not as a load reduction but as a capacity resource. This was covered in the response to LG&E KIUC 1-55, which was referenced in the response to LG&E AG 1-291, which Mr. Watkins references in his testimony.

Q. Is DOD witness Selecky correct that the LOLP allocator is principally determined by "top peak hours"?

A. Yes, the DOD witness makes an important observation, a fact that the AG's witness ignores completely. The Companies' peak load determines the amount of generation capacity that LG&E and KU must install. As shown in the following table (Table 2), almost 80% of the cumulative LOLP ("LOLP hours") are determined by 50 hours during the test year; approximately 90% of the LOLP hours are determined by 100 hours during the test year; and approximately 95% of the LOLP hours are determined by 150 hours during the test year:

CUMULATIVE PERCENTAGE OF LOLP TO TOTAL	NUMBER OF HOURS
78%	50 Hours
90%	100 Hours
95%	150 Hours
99%	300 Hours

TABLE 2

This table, which was constructed from the analysis included in Rebuttal Exhibit WSS-1, shows that with the LOLP cost of service study, 99 percent of fixed production costs are allocated to the customer classes on the basis of class demands for 300 hours of the year. ***<u>All</u>*** of these hours occur during either the Companies' winter or summer peak periods. None of the 300 hours occur during the spring or fall months (the so-called "shoulder months"). Furthermore, none of the 300 hours occur during off-peak nighttime hours. Therefore, the LOLP methodology appropriately allocates fixed production costs based on class loads during the Companies' peak load periods.

Q. What criticisms does the AG's witness have of the modified BIP methodology?

A. AG's witness Watkins states, "From a conceptual standpoint, Mr. Seelye's approach [using the BIP methodology] to allocate costs is reasonable."[17] His criticism is that the modified BIP methodology "does not reflect the actual mix of the supply resources ***utilized*** by LG&E."[18]

Q. The AG's witness places greater emphasis on how the generation resources are utilized than either you or the other intervenor witnesses. Is that correct?

A. Yes. Mr. Watkins argues that generation resources should be allocated to the customer classes based on how the generation resources are ***utilized***, whereas the other intervenor witnesses contend that generation resources should be allocated based on the amount of ***capacity required*** to serve customers. This is a major conceptual difference between the AG's witness and the other intervenor witnesses. Louisville Metro's witness captures the difference between the ***resources utilized*** and the ***capacity required*** perspectives succinctly:

> The obligation to serve means that when customers flip the switch, the light or air conditioning will turn on and the machine will operate. Thus, to ensure continuous service, the utility must size its capacity based on the projected system peak demand plus a margin to provide for contingencies such as forced outages, unexpected severe weather or load forecast error. If a utility were to size its generation capacity to meet average demand [i.e., utilization], it

[17] Watkins testimony at page 17, lines 1-2.
[18] Watkins testimony at page 15, lines 24-25. Emphasis added.

> could not provide continuous service.[19]
>
> … The reality is, as previously discussed, that the required amount of generation capacity is sized to meet a utility's peak demand. Further, an investment that is built to serve on-peak demand is also available to serve off-peak demand. In other words, off-peak usage is a *bi-product* of on peak usage… In summary, cost causation is primarily a function of peak demand. Thus, a proper cost allocation method should emphasize peak.[20]

Q. Which of these two perspective do you favor?

A. I am generally in agreement with the *capacity required* perspective. LG&E and KU's generation resources are sized to meet peak demands. Generation facilities are not sized to meet the annual utilization of the facilities. Increased peak demand will result in the need for additional generation resources; whereas greater utilization of the Companies' generation resources will not result in additional resources. In fact, greater utilization of the generation resources during off-peak periods will typically result in lower unit costs. Therefore, with respect to cost of service, generation resources should be allocated on the basis of peak demands. While the utilization of the generation resources has nothing to do with cost of service, taking utilization into account may appeal to someone's sense of *fairness*. By "fairness" I am not, at this point, referring to the regulatory standard of establishing fair, just and reasonable *rates*, which inevitably relies on principles of cost causation; rather, what I am referring to here is the notion that fairness should be baked into the determination of *cost of service*. I do

[19] Pollock testimony at page 43, lines 16-22.
[20] Pollock testimony at page 45, lines 8-15.

not believe that the views on fairness, in this sense, have any place in the determination of *cost of service*. As the Louisville Metro witness points out, *generation resources are sized to meet peak demands*; therefore, peak demands are what drive the Company's fixed production costs, not the utilization of the facilities by customers. To state it plainly, a study that allocates fixed production costs purely on the basis of utilization cannot truly be considered a *cost of service study*. In fact, a study that allocates fixed production costs entirely on the basis of utilization should more accurately be characterized as a "fairness study".

Q. Does fairness have a place in the determination of *rates*?

A. Yes, particularly with respect to the regulatory concept of fairness of *rates* reflected by the "fair, just and reasonable" standard. While the concept of fairness should not be artificially embedded into a cost of service study, certain principles reflective of the fair, just and reasonable rate standard should, and must, be considered in setting rates. For example, a concern that I would have with relying on a single CP to allocate fixed production costs, even though there might be a theoretical justification for the use of a single summer CP allocator, is that it is possible, even likely, that certain rate classes would not be allocated any fixed production costs, even though the classes would certainly utilize the utility's generation resources. A case in point is street lighting service, which was mentioned earlier. If a single summer CP were used to allocate fixed production costs on LG&E and KU's systems, street lighting classes would receive no allocation of fixed production costs. Clearly, street lighting customers do not take power during the Companies' summer peak periods and should receive a lower relative allocation than other rate classes, but it would be unreasonable for street lighting customers to pay zero cost for the production facilities that they utilize. Therefore, as a general principle, all customer classes should pay *some* fixed production costs.

Q. But are street lighting rates assigned zero fixed production costs with either the LOLP or modified BIP methodologies?

A. No. The concern is more theoretical than real with the Company's cost of service studies. With the LOLP and the modified BIP methodologies, all rate classes are allocated a portion of fixed production costs. However, this would not be the case for the single summer CP methodology suggested by KIUC's witness. Under a single summer CP methodology, street lighting would *not be allocated any* fixed production costs.

Q. Do you agree with the Probability of Dispatch ("POD") methodology proposed by the AG's witness?

A. No. The POD methodology assigns the fixed costs for each power plant ratably to each hour of the year based on the unit's output for the hour. These hourly fixed costs are then allocated to each rate class on the basis of the hourly loss-adjusted load for each rate class. Thus, the POD methodology allocates fixed production costs based purely on the hourly *utilization* of each power plant to serve the load. The POD methodology therefore does not reflect the capacity installed to serve the class load but only the utilization of the generation plants to provide service to customers. The POD methodology favors rate classes that have high peak demands (kW) but low amounts of energy (kWh) and penalizes rate classes that have high energy usage (kWh) but lower relative demands (kW). In other words, the POD methodology penalizes classes that have high load factors, e.g., more constant load patterns. (*Load factor* is the ratio of average demand to peak demand.) The POD methodology does not assign costs in a manner that reflects how generation capacity was installed or how the costs were planned. The POD methodology is a perfect example of a study that adheres to the perspective that fixed production costs should be allocated on the basis of ***utilization***. Consequently, the POD methodology does not provide useful information concerning cost of service, but instead attempts to provide *fairness* but in a counter-intuitive and counter-productive way, by penalizing customers that improve their load factors by using more energy during off-peak peaks.

Q. Why is it problematic to consider the utilization of the power plants in allocating costs?

A. The *utilization* of the power plant has little or no bearing on the Company's fixed production costs that have been installed to serve customers. To demonstrate this, consider the situation where a customer or customer class increases its off-peak usage of electric energy. Increasing usage during the off-peak period will not increase the Company's fixed production costs. Increases in off-peak usage can be served with existing generating resources and will not result in the need for additional generation capacity. If anything, increased utilization during off-peak periods will lower generation costs over the long run. This is not the case with increases in demand during on-peak periods. Because utilities install generation capacity to meet maximum on-peak demands, increases in on-peak demands will ultimately result in additional capacity and in additional fixed costs. Because the AG's POD methodology allocates a significant portion of fixed costs to the off-peak utilization of the Company's generation resources, the methodology fails to accurately reflect cost of service. As I have indicated, the POD methodology has more to do with the concept of fairness, an abstract and ultimately subjective idea, rather than with cost of service.

Q. Besides the POD methodology, does the AG's witness recommend any other changes to the cost of service study?

A. Yes. Mr. Watkins proposes that primary distribution costs should be classified entirely as demand-related.

Q. Do you agree with Mr. Watkins' proposal to classify primary distribution costs entirely as demand-rated?

A. No.

Q. How were primary distribution costs classified in the Company's cost of service study?

A. In the cost of service studies filed by LG&E in this proceeding, primary distribution costs, secondary distribution costs, and line transformers were classified as demand- and customer-related using the zero-intercept methodology. With the zero-intercept methodology, a statistical analysis is performed to determine the fixed-cost components of overhead conductor, underground conductor, and transformers that do not vary with demand, but would still vary with the number of customers. This methodology has been used for decades for both LG&E and KU. The zero-intercept methodology has also been accepted by the Commission in a number of rate cases. The Commission found LG&E's cost of service studies utilizing the zero-intercept methodology submitted in Case No. Case No. 90-158 to be reasonable. The Commission also found the embedded cost of service study submitted by Union Light Heat and Power in Case No. 2001-00092, which utilized the zero-intercept methodology, to be reasonable. Furthermore, the zero-intercept methodology has been used in every cost of service study filed by both KU and LG&E since the early 1980s, including the cost of service studies filed in Case Nos. 2014-00371 and 2014-00372, the Companies' last general rate case filings. In his cost of service study, the AG's witness accepts the Company's classifications of secondary distribution costs and transformer costs, which were based on zero-intercept calculations. Instead of classifying a portion of primary distribution lines as customer-related and a portion as demand-related, as in previous cost of service studies approved by the Commission, Mr. Watkins allocated primary distribution lines entirely as demand-related. The consequence of his proposal is to allocate proportionately more primary distribution costs to the customer classes with large users, particularly classes with large manufacturing customers.

Q. What reasons does Mr. Watkins give for making this change?

A. Mr. Watkins tries to link differences in the "mix of customers" across "customer density levels" to the notion that no portion of primary distribution lines are customer related. By "mix of customers", Mr. Watkins is referring to the percentage of customers in a region that are either residential (Rate RS), small commercial (Rate GS), medium commercial and industrial (Rate PS), large industrial (Rate TODS, TODP, RTS), etc. He states that "the only reason why it may be appropriate to allocate a portion of distribution plant expenses based on number of customers, rather than peak demand, is due to the possibility that the mix of customers varies significantly across the customer density levels within LG&E's service territory."[21] But Mr. Watkins fails to explain why either the *mix of customers* or *customer density levels* have anything to do with allocating distribution facilities on the basis of the number of customers.

Q. Do either the *mix of customers* or *customer density levels* for a zip code have anything to do with classifying distribution costs as customer-related?

A. No. When new customers are added to LG&E's distribution system, the Company will typically install primary lines, transformers, secondary lines, service lines, meters and other equipment. As new customers are added, the Company will typically install both primary and secondary lines, particularly as customer growth radiates away from urban centers, which is how LG&E experiences most of its customer growth. Furthermore, primary and secondary lines must be installed regardless of the customer's rate classification. Thus, *customer mix* has nothing to do with whether primary lines are installed. The appropriateness of classifying primary and secondary lines as customer-related therefore does not hinge on "the possibility that the mix of customer varies significantly across the customer density levels within LG&E's service territory."

[21] Watkins testimony at page 35, lines 9-12.

Q. In reaching his conclusion did Mr. Watkins analyze costs?

A. No. He constructs a graph of customers per square mile versus class percentage of total customers by zip code. He then claims that because the correlation coefficients between the customers per square mile versus the percentage of residential or general service customers to total customers is zero that there is no basis for classification of distribution plant on the basis of the number of customers. He also constructs a table cross referencing the number of customers in various customer density strata by rate schedule and comes to a similar conclusion. But he provides no information whatsoever on whether ***costs*** increase with the addition of customers. In fact, his analysis does not examine costs at all. Mr. Watkins posits that there *may be* a relationship between customer density and costs, but he is careful not to claim that there is in fact any such relationship. Mr. Watkins states, "***While it is possible*** that it technically costs more to serve a rural customer versus an urban customer, regulatory policy in the United States has generally been not to price discriminate based on customer densities, urban versus rural, or other geographic differences."[22] This statement underscores the fact that Mr. Watkins did not perform a cost analysis by density level.

Furthermore, it is unclear what his measure of customer density (customers per square mile) tells us about electric service. A proper density measure for an electric utility is *customers per conductor mile*, not *customers per square mile*. Customers per

[22] Watkins testimony at page 33, lines 5-8. Emphasis added.

square mile is a purely topographical measurement that is unrelated to electric service. Customers per square mile should not be used as a proxy for customers per conductor mile because some sub-regions within a zip code may not be located near electric service lines.

Q. Is there any merit to the AG's proposal to classify primary distribution plant entirely as demand-related?

A. No. Mr. Watkins has not demonstrated that the cost of primary distribution facilities are invariant to the number of customers. The principal idea behind the zero-intercept methodology used by LG&E is to classify distribution costs based on the portion of distribution costs that are statistically unrelated to the load carrying capability of the facilities and are thus related to serving additional customers. In other words, the zero-intercept approach determines the portion of the cost of primary lines, secondary lines and transformers that do not vary with increases in demand. The validity of this approach is borne out by the fact that the Company installs primary lines, secondary lines and transformers when it adds new customers. For example, when the Company installs primary underground conductor to serve new customers, the cost of the trenching work and conduit installation does not vary with the customers' demand but with the fact that the customers were added to the system. These costs, which do not vary with demand, are incurred whenever a customer is added to the underground system. Therefore, it is inappropriate to classify all of the costs as demand-related as Mr. Watkins has done.

It should also be pointed out that there are numerous other internal inconsistencies with the various methodologies that Mr. Watkins uses in his proposed cost of service studies. For example, as discussed earlier, he proposes to allocate fixed production costs based on the *utilization* instead of *peak demand*, but for primary and secondary distribution plant, he ignores the concept of *utilization* in favor of allocation on the basis of *peak demand*. Further, in his gas cost of service study for LG&E, which will be discussed later in my testimony, Mr. Watkins reverts to an allocation based on the utilization of distribution mains.

C. KIUC'S POSITIONS ON CLASS COST OF SERVICE

Q. KIUC witness Baron points out errors in the hourly load data used to develop the demand allocation factors for the class cost of service studies. Do you agree with his observation?

A. Yes. Corrected hourly load data was provided in response to Supplemental Response to Question No. 109 filed March 28, 2017 to the Commission Staff's Second Request for Information dated January 11, 2017. The Company was unaware of the spreadsheet errors prior to reviewing Mr. Baron's testimony.

Q. Please describe the corrections made.

A. Two changes were made to the hourly class load profiles provided in this supplemental response. First, the ordering problem Mr. Baron identified was corrected by properly aligning the days in the Historical Period (July 2015 – June 2016) and the Forecasted Test Period (July 2017 – June 2018) based on the daily energy total rank. Second, a small change was made to hold the monthly FLS load factors for KU constant from the Historical Period to the Forecasted Test Period.

As indicated in the Company's response to LG&E AG 1-291(a), after ranking the days in each month of the Historical Period and Forecasted Test Period based on the daily energy total, the Company intended to align the days in the two periods based on rank so that the class load profiles in the Forecasted Test Period could be developed based on the class load profiles from the corresponding day of the Historical Period. As correctly pointed out by Mr. Baron, the days in the Historical Period and Forecasted Test Period were not properly aligned.

The Companies' methodology was developed to ensure that the class load profiles for the peak day of each month in the Forecasted Test Period are developed based on the class load profiles for the peak day of the Historical Period. On peak load days, the more weather-sensitive classes will typically have a greater share of total load. By misaligning the days in the Historical Period and Forecasted Test Period, the share of total load on peak days was understated for some of the more weather-sensitive classes (e.g., Residential) and overstated for some of the less weather-sensitive classes.

Q. What impact did the changes have on the class load profiles for the Forecasted Test Period?

A. The table below compares the revised summer and winter coincident peaks to the coincident peaks that were originally submitted. In the summer, load on peak days is shifted from the less weather-sensitive classes to the residential class. In the winter, the sensitivity of the residential class to weather is much less due to the penetration of natural gas heating in the LG&E service territory. As a result, correcting the ordering problem did not have as big an impact to the winter coincident peaks.

LG&E Coincident Peaks (MW)

	Summer				Winter			
	Original	Revised	Abs Change	% Change	Original	Revised	Abs Change	% Change
Residential	971	1,238	266	27%	750	728	-22	-3%
General Service	351	287	-64	-18%	245	268	23	9%
PS Primary	30	27	-3	-11%	20	22	2	11%
PS Secondary	409	345	-64	-16%	257	270	13	5%
TOD Primary	322	262	-59	-18%	210	206	-4	-2%
TOD Secondary	209	175	-34	-16%	137	143	6	4%
RTS	193	157	-36	-19%	129	111	-18	-14%
Spec Con Cust #2	8	7	-1	-8%	5	7	1	23%
Spec Con Cust #1	20	16	-4	-22%	15	13	-1	-10%
Unmetered Lighting	0	0	0	0%	0	0	0	0%
Traffic Energy Svc	0	0	0	0%	0	0	0	0%
Lighting Energy Svc	0	0	0	0%	0	0	0	0%

TABLE 3

The demands in the above table are shown at the customer delivery level and must be loss-adjusted for use in the cost of service study. The loss-adjusted demands were shown in the file attached to the Supplemental Response to Question No. 109 of the Commission Staff's Second Request for Information.

Q. Have you updated the class cost of service studies to reflect the corrected load data?

A. Yes. The effect of these changes on the cost of service studies is summarized in the Supplemental Response to Question No. 53 filed March 28, 2017 to the Commission Staff's First Request for Information Dated November 10, 2016.

Q. What impact did the corrections have on the class rates of return?

A. Correcting the hourly load data had less of an impact on the Base-Intermediate-Peak (BIP) study than the Loss of Load Probability (LOLP) study.

Q. Please describe the impact of the corrections on the BIP cost of service study.

A. The following table (Table 4) compares the class rates of return from the original BIP study to the rates of return for the corrected study, also showing the percentage-point change in the rates of return:

Rate Class		BIP Method Original ROR	Corrected ROR	Percentage Point Difference
Residential Rate RS		2.65%	2.62%	-0.03%
General Service		7.34%	7.37%	0.03%
Power Service Primary Rate PS		6.49%	6.58%	0.09%
Power Service Secondary Rate PS		8.84%	8.89%	0.06%
TOD Rate TOD Primary		4.57%	4.52%	-0.05%
TOD Rate TOD Secondary		11.92%	12.03%	0.11%
Retail Transmission Service Rate RTS		3.48%	3.70%	0.22%
Special Contract #1		1.70%	2.05%	0.35%
Special Contract #2		2.45%	2.45%	0.00%
Lighting Rate RLS & LS		5.39%	5.27%	-0.13%
Lighting Rate LE		8.01%	6.85%	-1.16%
Lighting Rate TLE		7.62%	7.27%	-0.35%
Total		4.92%	4.92%	

TABLE 4

As seen from the table, correcting the spreadsheet error had a relatively small impact on the class rates for return, with only one class showing a percentage-point difference greater than ±1%. The largest difference is for Lighting Energy Rate LE, which is an energy only rate provided to customers that own their own lights. There are very few customers that take service under Rate LE.

Q. Please describe the impact of the corrections on the LOLP cost of service study.

A. The following table (Table 5) compares the class rates of return from the original LOLP study to the rates of return for the corrected study:

	LOLP Method		
Rate Class	Original ROR	Corrected ROR	Percentage-Point Difference
Residential Rate RS	2.04%	1.74%	-0.30%
General Service	8.65%	8.42%	-0.22%
Power Service Primary Rate PS	7.03%	7.80%	0.77%
Power Service Secondary Rate PS	9.70%	10.14%	0.45%
TOD Rate TOD Primary	5.39%	6.16%	0.77%
TOD Rate TOD Secondary	11.90%	12.79%	0.89%
Retail Transmission Service Rate RTS	4.83%	6.61%	1.78%
Special Contract #1	2.18%	4.08%	1.90%
Special Contract #2	3.11%	4.01%	0.90%
Lighting Rate RLS & LS	6.01%	5.90%	-0.11%
Lighting Rate LE	17.55%	15.12%	-2.43%
Lighting Rate TLE	10.39%	9.91%	-0.48%
Total	4.92%	4.92%	

TABLE 5

As can be seen from this table, correcting the spreadsheet error in the LOLP study has a more significant impact on the class rates for return, with percentage-point differences in rates of return for three classes exceeding ±1%. Again, the largest decrease is for Lighting Energy Rate LE, which decreased from 17.55% to 15.12%. The largest increases in rates for return were for Retail Transmission Service, which increased from 4.83% to 6.61%, and for Special Contract #1, which increased from 2.18% to 4.08%.

Q. Will the correction affect LG&E's proposed allocation of the revenue increase?

A. No. Revenue allocation will be discussed in the next primary section of my testimony.

D. RECOMMENDATION

Q. What is your recommendation regarding the class cost of service study?

A. It is my recommendation that the Commission make a determination that the LOLP cost of service study, as corrected, is reasonable and should be used as a guide for establishing rates. As an alternative, and as an initial step toward adopting the LOLP methodology, the class rates of returns could be averaged, as suggested by Kroger's witness, for purposes of determining the revenue allocated to each rate class. I recommend that the Commission reject the AG's proposed cost of service methodology.

III. ALLOCATION OF THE ELECTRIC REVENUE INCREASE

A. OVERVIEW OF THE POSITIONS OF THE PARTIES

Q. Please describe how LG&E proposed to allocate the revenue increase to the rate classes.

A. LG&E relied on the results of the class cost of service studies to allocate the overall revenue increase to the rate classes. In general, the Company proposed higher percentage increases for the rate classes that have low rates of return and lower percentage increases for classes that have higher rates of return. In developing the proposed percentage increases, the Company considered both the BIP cost of service study and the LOLP cost of service study, but gave more weight to the LOLP cost of service study. For the most part, the percentage increases proposed for the rate classes were inversely proportional to the class rates of return from the LOLP study. The decision was made to cap the increase for Residential Service (Rate RS), the class with the lowest rate of return, at approximately 1 percentage point above the overall average for all classes. LG&E did not propose an increase for Lighting Energy Rate LE.

Q. Do the revisions to the cost of service studies correcting the spreadsheet error in the development of the hourly class load data require a modification to the Company's proposed allocation of the revenue increase to the rate classes in this proceeding?

A. No. While the revisions to the cost of service studies do affect the class rates of return, they did not change the results enough to warrant a change in the Company's proposed allocation of the revenue increase. As can be seen from the following table, the proposed percentage increases for the rate classes are still generally in line with the results of the cost of service study:

Sorted by Increase			
	Rate of Return on Rate Base		Revenue
Rate Class	BIP Version	LOLP Version	Increase
Residential Rate RS	2.62%	1.74%	9.54%
Special Contracts	2.25%	4.06%	8.69%
Retail Transmission Service Rate RTS	3.70%	6.61%	8.45%
Power Service - Primary	6.58%	7.80%	8.25%
Time-of-Day Primary Service	4.52%	6.16%	8.22%
Lighting Service & Restricted Lighting Service	5.27%	5.90%	8.21%
General Service	7.37%	8.42%	7.15%
Power Service - Secondary	8.89%	10.14%	7.05%
Traffic Energy Service	7.27%	9.91%	6.76%
Time-of-Day Secondary Service	12.03%	12.79%	6.75%
Lighting Energy Service	6.85%	15.12%	0.00%
Total All Classes	4.92%	4.92%	8.52%

TABLE 6

As shown in the above table, the proposed percentage increases are still generally consistent with the results of the BIP and LOLP cost of service studies. Possible exceptions might be that a slightly higher increase might be justified for Lighting

Service & Restricted Lighting Service and a slightly lower increase might be justified the Power Service – Secondary rate class.

Q. What are the intervenor positions on allocating the revenue increase to the classes of service?

A. Because of the spreadsheet error that Mr. Baron identified, KIUC's witness proposes to increase each rate class by the same percentage.

The AG's witness claims that the Company "has limited individual class increases somewhat too narrowly."[23] In developing his proposed allocation of the revenue increase, Mr. Watkins relies on the results of the LOLP study, the BIP study and his own POD study.

Louisville Metro recommends allocating the increase to follow more closely the results of the LOLP cost of service study. Specifically, Louisville Metro proposes to assign much more of the increase to residential customers and the special contracts. In developing his proposed increases, Mr. Pollock removed embedded fuel costs from the analysis and capped the maximum increase for any class, excluding fuel costs, at 150% of the overall increase, net of fuel costs. This results in a 21.2% increase for Residential Service (Rate RS) and for the special contracts.

Kroger's witness recommends using an average of the LOLP and BIP cost of service studies to develop an allocation of the revenue increase and to significantly reduce subsidies. Kroger recommends that Time-of-Day Secondary (TODS) and

[23] Watkins testimony at page 47, lines 2-3.

Lighting Energy (LE) receive no increase.

Walmart does not oppose the Company's revenue allocation. The DOD recommends using the LOLP cost of service study for allocating the revenue increase to the rate classes. The DOD's witness does not provide specific recommendations regarding what the percentage increases for the rate classes should be.

Q. Do you agree with the KIUC's witness that the spreadsheet error necessitates increasing all rate classes by the same percentage increase?

A. No. LG&E used a tight bandwidth for the percentage increases, in the sense that the bandwidth between lowest percentage increase to the highest percentage increase for any single rate class was fairly narrow. Except for Lighting Energy (Rate LE), the percentage increases ranged from 6.75% to 9.54%. KIUC's proposal to increase all rate classes by the same percentage is therefore not a major departure from what the Company proposed. Yet, even though the Company did not propose a large correction in the proposed rates to address interclass subsidies, it is reasonable to give at least *some consideration* to the class rates of return from cost of service study, as corrected, in determining the percentage increases. The class rates of return did not change significantly after correcting the load data used to develop the allocation factors in the cost of service studies. Indeed, after correcting the error identified by Mr. Baron, the class rates of return did not change enough to support applying a uniform increase for all rate classes. Thus, there is no justification for increasing all rate classes by the same percentage.

Q. Do you agree with the recommendation made by the AG's witness?

A. No. As explained earlier, the POD cost of service methodology proposed by Mr. Watkins is flawed and should not be used for setting rates. While Mr. Watkins uses a combination of the results for the LOLP, BIP and POD cost of service studies, his proposed allocation would be weighted to include the results of methodologies (specifically the POD and the BIP) that give too much consideration to the utilization of power production facilities as opposed to principles of cost causation.

Q. What is your reaction to Louisville Metro's recommendation?

A. Louisville Metro's proposed methodology is fundamentally sound from a cost of service perspective. Mr. Pollock's reliance on the LOLP cost of service study has merit, and so does his revenue impact analysis which removes fuel costs. However, the maximum increase proposed by Louisville Metro of 21.2% for Residential Service (Rate RS) and for the special contracts is larger than what I would recommend.

Q. Do you agree with the recommendation made by Kroger?

A. Kroger's recommendation of using the average rates of return from the LOLP and BIP cost of service studies for purposes of allocating the revenue increase is not without merit. Taking into account the average rates of return from the two methodologies could be a way to make a gradual transition to a full recognition of the LOLP methodology in future rate cases. The following table shows the average rates of return based on the two methodologies:

Rate Class	Rate of Return on Rate Base BIP Version	LOLP Version	Avg of BIP & LOLP
Residential Rate RS	2.62%	1.74%	2.18%
General Service	7.37%	8.42%	7.90%
Power Service - Secondary	8.89%	10.14%	9.51%
Power Service - Primary	6.58%	7.80%	7.19%
Time-of-Day Secondary Service	12.03%	12.79%	12.41%
Time-of-Day Primary Service	4.52%	6.16%	5.34%
Retail Transmission Service Rate RTS	3.70%	6.61%	5.16%
Lighting Energy Service	6.85%	15.12%	10.99%
Traffic Energy Service	7.27%	9.91%	8.59%
Lighting Service & Restricted Lighting Service	5.27%	5.90%	5.58%
Special Contracts	2.25%	4.06%	3.15%
Total All Classes	4.92%	4.92%	4.92%

TABLE 7

While the average rate of return for Time of Day Secondary Service (Rate TODS) is higher than most other classes, the Company does not agree with Mr. Townsend that the rate for this class should not be allocated an increase.

B. RECOMMENDATION

Q. What is your recommendation concerning allocating the increase to the rate classes.

A. As indicated earlier, based on the overall revenue increase proposed by the Company in this proceeding, the percentage increases originally proposed by LG&E in this proceeding are still reasonable. If the Commission determines that a different overall increase is justified, then I would recommend that the same general principles used by the Company to develop the proposed revenue increases, including the narrow bandwidth for the percentage increases, should be used to develop the approved increases.

IV. ELECTRIC RATE DESIGN

A. RESIDENTIAL RATE DESIGN

Q. Please provide a brief description of the Company's proposed charges for Residential Service Rate RS.

A. LG&E is proposing a Basic Service Charge of $22.00 per month and is proposing to decrease the energy charge from $0.08639 per kWh to $0.08471 per kWh. LG&E is also proposing to separate the energy charge into a Variable Energy Charge component and an Infrastructure Energy Charge component. The proposed Variable Energy Charge is $0.03681 per kWh and the Infrastructure Energy Charge is $0.04790 per kWh. Separating the two charges out in this manner is purely informational. The Company wants customers, stakeholders and employees to be aware that two types of costs are recovered through the energy charge for Rate RS -- fixed costs and variable costs.

Q. Do any of the intervenor witnesses address the proposed rates design charge for Rate RS?

A. Yes. The AG's rate witness, Mr. Watkins, and Sierra Club's rate witness, Mr. Wallach, both oppose the increase in Basic Service Charge and the informational change to the energy charge. Both witnesses recommend that the Basic Service Charge remain at its current level.

Q. Why does the AG's witness recommend against increasing the Basic Customer Charge?

A. The AG's witness performed what he called a "direct customer cost analysis" which results in a cost for residential customers of $4.15 per month. But he recommends maintaining the Basic Service Charge at the current level of $10.75 per month. He supports this proposal as follows:

> Although my residential customer cost analysis indicates a maximum monthly customer charge of $4.15 per month, I recommend maintaining the current customer charge of $10.75 per month. In this regard, I recognize that the current rate of $10.75 more [sic.] than double that of the direct customer cost, however, in the interest of rate continuity and rate stability, my recommendation of maintaining the current monthly customer charge is in the best public interest.[24]

Q. Do you agree with Mr. Watkins direct customer cost analysis?

A. No. His analysis fails to include costs that he classified as customer-related in his own cost of service study. While I am not in agreement with the AG's cost of service study, if all residential customer-related costs are identified from Mr. Watkins cost of service study, then his own cost of service study would show a customer cost of $12.84 per month. Specifically, Mr. Watkins excluded customer-related components of secondary distribution lines and transformers that were classified as customer-related in his own study. The purpose of rate design is to develop rates that reflect cost causation. Specifically, costs should be billed in the manner in which they are incurred and in the manner in which they are classified. The cost classification step in a cost of service study, by definition, reflects cost causation and thus represents the most appropriate, fair and equitable way to bill those costs. It is a major inconsistency with Mr. Watkins'

[24] Watkins testimony at page 63, lines 5-10.

proposed rate design that he ignored the principles of cost causation incorporated in his own cost of service study.

Q. Have you prepared an analysis correcting Mr. Watkins' customer cost calculation to include costs that were classified as customer-related in his own cost of service study?

A. Yes. Rebuttal Exhibit WSS-2 shows a corrected calculation that includes the customer-related cost components of line transformers and secondary lines. As can be seen from this exhibit, Mr. Watkins own cost of service study supports a customer cost of $12.84 per month. But as I mentioned earlier, I have a fundamental disagreement with the AG witness's failure to classify any primary distribution facilities as customer-related. If costs associated with the customer-related portion of primary distribution facilities are included in the customer cost calculation, then the cost is $22.04 as was show in Exhibit WSS-2 of my direct testimony.

Q. The Sierra Club takes the same position as the AG against increasing the Basic Service Charge. What is the Sierra Club's rationale for maintaining the charge at the current level?

A. As with the AG's witness, Sierra Club's witness claims that the Company has overstated its customer-related costs. Mr. Wallach, Sierra Club's witness, modified the Company's unit cost calculation for Residential Service Rate RS by excluding the customer-related portions of poles, conductor, and transformer costs. Mr. Wallach calculates a customer-related cost for residential customers of $8.01 per month. He refers to this as the "true cost", "incremental cost" and "minimum connection cost" for a residential customer.[25]

Q. Does Mr. Wallach's $8.01 per month cost reflect the "incremental cost" or "minimum connection cost" for a residential customer?

A. No. Mr. Wallach's $8.01 per month cost comes nowhere close to reflect the incremental cost of connecting a new customer. Based on the actual cost of connecting 63 typical residential customers in 2016, the total cost of providing overhead service was $94,433, resulting in an average cost of $1,499 per customer. For a residential customer served from the Company's underground system the upfront cost is even higher. The equivalent cost to connect a residential customer with underground service is $1,742. It is important to understand that LG&E incurs these costs regardless of what the customers' energy usage turns out to be. Obviously, the customers being connected are free to take measures to keep their energy usage to a minimum by installing high efficiency appliances, adding solar panels, or simply closely monitoring their energy usage. Consequently, regardless of a customer's energy usage, the Company will have incurred an upfront fixed cost of $1,499 to connect a residential customer with overhead service or a cost of $1,742 to connect a residential customer with underground service.

Q. LG&E incurs an upfront cost of $1,499 to connect a residential customer taking overhead service and $1,742 to connect an underground residential customer, but what are the estimated monthly fixed carrying costs associated with these

[25] Wallach testimony at page 9, lines 3 and 8, and page 12, lines 9-11.

expenditures?

A. As shown in Rebuttal Exhibit WSS-3, the estimated monthly incremental cost of connecting a new customer is $23.25 per month for a residential customer taking overhead service and $27.02 per month for a residential customer taking underground service. Since LG&E connects more new underground customers than overhead customers, the average monthly carrying charges of connecting a new customer will be closer to $27.02. LG&E is proposing a Basic Service Charge of $22.00 per month. The Company's Basic Service Charge falls short of covering the incremental cost of connecting a new customer to the system, let alone providing recovery of costs of the backbone distribution system in place to deliver power to the customer.

Q. But considering how he performed his calculation, does Mr. Wallach's $8.01 cost in fact reflect the "incremental cost" or "connection cost" for a residential customer?

A. No. Although Mr. Wallach refers to the cost as an "incremental cost" and a "connection cost" for a residential customer, his costs were derived from the Company's *embedded* cost of service study. "Incremental cost" refers to the marginal cost of connecting a new customer to the system. While marginal or incremental costs are certainly important for various evaluations, the Company's cost of service study is *not* a marginal cost of service study and does not contain any marginal or incremental costs. An embedded cost of service study reflects accounting costs and represents the test-year revenue requirements determined on net depreciated plant for the utility; whereas, a marginal cost of service reflects the cost of adding new customers, energy or demand.

In calculating customer-related costs, both the AG and the Sierra Club's witnesses simply excluded certain costs that were classified as customer-related in the Company's cost of service study. It is important to recognize that the Commission has accepted the Company's classification of customer-related costs in a number of rate case proceedings.

Q. What is your recommendation concerning the level of LG&E's residential customer charge?

A. It is my recommendation that the Commission approve the Basic Service Charge for Rate RS that was proposed by the Company. The level of the charge represents customer-related costs from the Company's cost of service study using a methodology for classifying customer-related costs that has been accepted by the Commission in prior rate cases. Furthermore, LG&E's proposed charge is not out of line with basic service charges of other utilities across the U.S. Almost all the electric utilities I work with across the country have basic customer charges in the $20 to $40 per month range.

Q. Both the AG and Sierra Club witnesses object to the Company's proposal to separate the residential energy charges into "fixed" and "variable" costs components. Does the Company's proposal have an effect on the proposed energy charge?

A. No. The Company is separating out the energy charge into Variable Energy Charge and Infrastructure Energy Charge components. The proposal is for informational purposes only and will not affect the amounts billed to customers.

Q. Did either the AG or the Sierra Club provide calculations demonstrating costs

included in the Infrastructure Energy Charge were not related to the costs of the Company's infrastructure?

A. No.

Q. Then what are the Sierra Club and the AG's objection to separating the charge out for informational purposes.

A. Sierra Club's witness offers the following objection:

> The Commission should reject this proposal because it will serve to confuse and misinform residential customer regarding the distinction between the "fixed" and "variable" costs recovered in the energy rate and regarding the extent to which recovery of "fixed" costs in the energy rate contributes to intra-class subsidization.[26]

The AG's witness has a similar complaint:

> First, even for those customers that understand the concepts of fixed versus variable costs, they could care less [sic] about the cost structure for ratemaking purposes within their energy charges. What the customer is interested in is what those variable charges are in total. As an analogy, when consumers purchase gasoline, they could care less [sic] how much of the total cost per gallon is associated with the fixed cost of producing, transporting, and delivering that gallon of gasoline versus the variable cost of gasoline at the wellhead. Second, in my practice throughout the United States, I have not seen such as proposal, let alone the bifurcation of rates between "fixed" and "variable" costs. This could lead to additional customer confusion as they may not understand the distinction between "fixed" and "variable" costs, and perhaps more importantly, may disagree with the Company's determination of what is and what is not a fixed cost.[27]

Both the Sierra Club and AG's witnesses are concerned about the customer confusion

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[26] Wallach testimony at page 20, lines 6-10.
[27] Watkins testimony at page 64, lines 28-33, continuing on to page 65, lines 1-5.

that the Company's proposal might cause.

Q. Will the change cause customer confusion?

A. No. I have worked with utilities all over the country that have incorporated unbundled rates. While Mr. Watkins claims he has not seen this type of separation in utilities' rates, it is common for utilities to break out various components of their costs, such as distribution delivery costs from production or purchased power costs. In Kentucky, LG&E's (and other gas utilities') gas rates have been separated into variable and infrastructure cost components for decades, including the gas rates applicable to residential customers. LG&E's gas supply costs (which are variable costs) are recovered entirely through the Gas Supply Cost Component of its residential rates, while infrastructure costs are recovered through the Distribution Cost Component.[28] Though Mr. Watkins claims he has "not seen such a proposal, let alone such a bifurcation of rates," he obviously failed to examine LG&E's current residential gas rates, because the rates include the same type of "bifurcation". In fact, it was the Commission that ordered the "bifurcation" by separating out the Distribution Cost Component and the Gas Supply Cost Component from LG&E's total cost per Ccf. The reason that the Commission gave for ordering the separation was to "*avoid customer confusion*."[29]

I agree with the thinking in the Commission's Order in Case No. 9133.

[28] In this proceeding, LG&E has proposed to show the Gas Supply Component of the rates on a separate page, but the separation of residential and other rates into the two components will continue.
[29] See Order in Case No. 9133 dated January 7, 1985, at page 2. Emphasis added.

Bundling costs together causes more confusion than breaking them out. Separating the energy charge into a Variable Energy Charge and Infrastructure Energy Charge will provide useful information to interested stakeholders, including customers, the Commission, the Company's employees, and others. Undoubtedly, the Company's proposal has already generated discussion about the costs that are included in the energy charge, based on the response of the Sierra Club and the AG.

Q. Mr. Watkins makes the point that there isn't universal agreement on what constitutes "fixed" and "variable" costs. Do you agree?

A. Regardless of any possible differences in opinions about "fixed" and "variable" costs, the Company is not proposing to use "fixed costs" as the designation of the non-variable component of the energy charge. LG&E is proposing to call the component the *Infrastructure Energy Charge*. Mr. Watkins seems to be making the point that in the very long run all costs are "variable", including fixed costs. This recalls the remark made by John Maynard Keynes that "in the long run we are all dead."[30] But the standard way of looking at "fixed costs" is to consider fixed costs to be related to the costs, such as capital related costs, that are currently in place to provide service to customers, or that are in place for a period of time into the future.[31] Despite the lack

[30] *A Tract on Monetary Reform* (1923), Ch. 3, p. 80.
[31] The classic text _Cost Accounting_ by P. K. Jain states as follows:

> [F]ixed costs are associated with inputs that do not fluctuate in response to change in the total activity or output of the firm, within relevant range. They may also be called non-variable costs. They are normally fixed for a relevant range of volume but fluctuate beyond that range. Moreover, fixed costs are to be analysed in relation to a given period of time. (Section 14.12)

of clarity that Mr. Watkins wants to attribute to the term "fixed costs," there is no such lack of clarity about "*infrastructure costs*". Neither the AG witness nor the Sierra Club witness has argued – nor can they argue – that the costs included in the Infrastructure Energy Charge are unrelated to infrastructure costs. In the very, very long run, the costs included in the Infrastructure Energy Charge may not be "fixed," but they are certainly *infrastructure* costs.

Q. What is your recommendation about separating the energy charge into a Variable Energy Charge and an Infrastructure Energy Charge?

A. I recommend that the Commission approve the Company's proposal. I generally believe that it is better to provide more, not less, information to customers. In fact, I am surprised that anyone would prefer to keep people in the dark. In its Order in Case No. 9133, the Commission determined that it was important to implement a similar separation in LG&E's gas rates. The Company's proposal will provide additional information to its customers, employees and other stakeholders about what types of costs are included in the Company's rates.

B. CURTAILABLE SERVICE RIDER (CSR) CREDITS

Q. Briefly, what is the Curtailable Service Rider?

A. The Curtailable Service Rider (CSR) is a rider that provides a credit to industrial or commercial customers that will interrupt a portion of their load when called upon by LG&E. Curtailable customers receive a discount in the form of a credit to their demand charges in exchange for their willingness to receive curtailable service on a designated portion of their load.

Q. What CSR credits is the Company proposing?

A. LG&E is proposing to lower the CSR credit from $6.40 to $3.56 per kVA for transmission voltage service and from $6.50 to $3.67 per kVA for primary voltage service. The Company is proposing to restrict the rider so that it will only be available to customers served under the schedule as of the date new rates go into effect as a result of this proceeding.

Q. How were the proposed CSR credits determined?

A. The credits were determined based on the fixed carrying costs of LG&E's share of the large-frame combustion turbines jointly owned by LG&E and KU.

Q. What positions do the intervenor witnesses take on the proposed CSR credits?

A. The level of the credits is addressed by two intervenor witnesses – KIUC witness Goins and Louisville Metro witness Pollock. Mr. Goins recommends that the Commission reject the Company's proposed reduction in the CSR credits. He recommends that the Commission continue to use avoided costs as the basis for setting rates. Although Mr. Pollock makes no specific recommendation concerning what the CSR credits should be, he states that "LG&E's proposal reducing the Curtailment Service Rider credit by 44% violates gradualism because it would represent a price change that exceeds 1.5 time the system-average increase that LG&E is seeking in this case."[32]

Q. Mr. Goins states that the CSR credit should be based on avoided costs. Did he

[32] Pollock testimony at page 53, lines 1-3.

perform an avoided cost calculation?

A. No. He simply recommends leaving the CSR credits at their current level without demonstrating that the current CSR credits are reasonable in comparison to avoided costs.

Q. Please explain the difference between an avoided cost approach and the embedded cost approach used by the Company to calculate the CSR credits.

A. With the *embedded cost approach* used by Company in this proceeding, the credits were calculated based on the current carrying costs of LG&E's large-frame peaking units. With no imminent need for additional generation capacity, the Company concluded that using the cost of the Company's current generation resources provides a better measure of the savings already built into the system from providing curtailable service to CSR customers.

An *avoided cost approach* determines the cost that would be avoided *in the future* from adding additional curtailable load. Any future savings from serving curtailable load would not be realized for more than a decade, and likely 30 years or more. Avoided costs can be calculated based on the levelized cost per kW of the generation resource *avoided by* the curtailable load or based on the cost of generation resources *deferred by* the curtailable load. An avoided cost approach is essentially a marginal cost methodology that analyzes the change in future costs due to a change in load, in this instance a decrease in load created by curtailable service. Using avoided cost is a theoretically sound approach for evaluating the economic value of curtailable service. While there are a couple of approaches for calculating avoided costs, the standard methodology is to calculate levelized carrying charges associated with the present value revenue requirements of the utility's next generating unit, typically assumed to be a peaking unit.[33] The only problem with determining the avoided cost of curtailable load based on a combustion turbine is that the operational characteristics of curtailable load are not equivalent to a combustion turbine. For example, there is no assurance, despite penalties for a failure to curtail, that a CSR customer will interrupt its load when called upon to do so. Additionally, a combustion turbine typically can be brought on line in a matter of minutes; whereas, pursuant to the Company's tariff, a CSR customers has an hour to curtail its load. Also, physical curtailments under the Rate CSR are limited to 100 hours per year; whereas, a combustion turbine can be operated for as many hours as needed. These differences in the operational value of curtailable load compared to combustion turbine capacity are discussed in the Direct Testimony of David Sinclair.

Q. Setting aside the operational differences between a combustion turbine and curtailable load, please explain why an avoided cost approach would not support leaving the CSR credits at their current levels.

A. LG&E and KU jointly plan their generation resources. According to the most recent Integrated Resource Plan ("IRP") filed by KU in 2016 in Virginia, the Companies will

[33] An alternative approach is to determine avoided costs on the basis of the change in present value revenue requirements resulting from delaying a combustion turbine due to adding a block of curtailable load. This methodology will result in a lower level of avoided costs.

need no additional generation capacity until 2029.[34] However, based on a more recent assessment by the Companies, LG&E and KU are projected not to need additional generation capacity throughout its 30-year forecast horizon.[35] Therefore, any avoided costs (i.e. reduced revenue requirements) from curtailable load would not occur until 2029, but, more likely, not for more than 30 years from now, which place the need for new generation beyond 2047.

Considering how far out the Companies' current need is for additional generation capacity, an argument could be made that the avoided cost of CSR load is currently zero. But based on the Companies' current generation resource planning horizon, the Virginia IRP filed in April 2016 would place the need for additional generation resources in the year 2029, while the Companies' current Business Plan would not place the need for additional generation capacity until *at least* the year 2048 (i.e., one year beyond the Company's 30-year planning horizon.) Therefore, avoided costs could be estimated based on two scenarios: First, assuming the installation of new generation capacity would take place in the year 2029; second, assuming the installation of new generation capacity would take place in the year 2048. Obviously, changes will almost certainly take place in the intervening years between now and 2029 or 2048,[36] but calculating avoided costs using these two timeframes will serve to

[34] See IRP filed April 29, 2016, with the Virginia State Corporation Commission in Docket No. PUE-2016-00053.
[35] See 2017 Business Plan – Generation & OSS Forecast dated August 12, 2016, supplied as an Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)H, page 4. Also, see Rebuttal Testimony of David S. Sinclair, page 2.
[36] Between now and 2029 (or 2048), there could be changes in load patterns, peak demands, and the introduction of new electric generation, energy storage, and end-use technologies.

bracket the Companies' avoided costs based on information that has been submitted into the record in this proceeding.

As discussed earlier, a standard approach for calculating avoided costs is to determine the levelized revenue requirements of a combustion turbine. For example, based on information from the Virginia IRP, a sufficiently large block curtailable load would allow the Company to *avoid* the generation capacity that is anticipated to be needed in 2029. Therefore, the first avoided cost scenario would calculate the levelized revenue requirements of the combustion turbine from 2017 to the end of the expected useful life of the combustion turbine. Because the expected life of a combustion turbine is 30 years, the levelization period would be for the 42-year period beginning 2017 and ending 2058. Likewise, based on information from Companies' 2017 Business Plan, a sufficiently large block curtailable load would allow the Company to *avoid* the generation capacity anticipated to be needed no earlier than 2048. Therefore, the second avoided cost analysis would calculate the levelized revenue requirements of the combustion turbine from 2017 to the end of the expected useful life of the combustion turbine. Again, because the expected life of a combustion turbine is 30 years, the levelization period would be for the 61-year period beginning 2017 and ending 2078.

Q. Please explain how the levelized costs for the two scenarios would be calculated.

A. In calculating levelized costs related to avoiding the installation of a combustion turbine in 2029, the following steps would be required: (i) the PVRR of a combustion turbine ($/kW) would be calculated beginning in 2029, discounting the revenue requirements to 2017 dollars based on the Company's after-tax weighted cost of capital; (ii) the levelized revenue would be calculated by calculating the capital recovery factor (CFR) over 42 years based on the Company's after-tax weighted cost of capital. This is a standard approach in the industry for calculating avoided costs.

In calculating levelized costs related to avoiding the installation of a combustion turbine in 2048, the following steps would be required: (i) the PVRR of a combustion turbine ($/kW) would be calculated beginning in 2048, discounting the revenue requirements to 2017 dollars based on the Company's after-tax weighted cost of capital; (ii) the levelized revenue would be calculated by calculating the capital recovery factor (CRF) over 61 years based on the Company's after-tax weighted cost of capital.

Q. Have you performed calculations for the two scenarios?

A. Yes.

Q. What assumptions were made in applying this procedure?

A. It was assumed that the installed cost of a combustion turbine in 2029 would be $806 per kW and that the cost of a combustion turbine in 2048 would be $1,174 per kW. These costs were determined by escalating the cost of a large-frame CT assumed in the Companies' 2014 IRP filing by 2% per year.[37] The cost of the large-frame CT was $587 per kW in 2013 dollars, which was escalated to $806 in 2029 dollars by applying a 2% escalation rate ($587 x 1.02^16 = $806) and to $1,174 in 2048 dollars ($587 x

[37] The cost of a combustion turbine from the 2014 Kentucky IRP filing was escalate by 2% per year in the 2016 Virginia IRP filing,

1.02^^{35} = $1,174). Annual revenue requirements were then calculated based on: (i) a 30-year service life; (ii) 20-year MACRS depreciation; (iii) the weighted cost of capital proposed by LG&E in this proceeding; (iv) a composite federal and state income tax rate of 38.64%; (iv) property taxes equal to 0.16% % of net plant; (v) fixed operation and maintenance expenses of $10.00 per kW-year in 2029 dollars and $14.60 in 2048 dollars; and (v) a 2% escalation rate for operation and maintenance expenses.

Q. Have you prepared an exhibit showing the calculation of the avoided costs for the two scenarios?

A. Yes. The avoided cost calculation is shown in Rebuttal Exhibit WSS-4 shows the calculation of avoided costs assuming the addition of a combustion turbine in 2029. Rebuttal Exhibit WSS-5 shows the calculation of avoided costs assuming the addition of a combustion turbine in 2048.

Q. What do these avoided cost calculations show?

A. The avoided cost calculation for the scenario calling for additional capacity in 2029 would result in an avoided cost for a demand reduction for CSR load of $3.37 per kW per month. The avoided cost calculation for the scenario calling for additional capacity in 2048 would result in an avoided cost of $1.36 per kW per month, without considering losses. Thus, based on the two scenarios, avoided generation capacity costs would range from $1.36 to $3.37 per kW-month.

Q. Do you have any observations about the avoided cost?

A. Yes. The reductions in revenue requirements associated with additional CSR load would not occur until <u>*at least*</u> 2029, and more likely not before 2048. If the Company were to enroll more load under CSR, then there would likely be no savings until 2048, but no earlier than 2029. Therefore, the Company would be crediting customers for curtailable load during the intervening 31 years (i.e. from 2017 until 2048) without realizing a reduction in revenue requirements during those intervening years. Between now and until any capacity could be avoided, there would be no cost savings to the Company from taking on additional curtailable load. This is the principal reason that the Company is proposing not to allow additional CSR load under the tariff at this time. Allowing new customers to sign up under CSR would result in current non-curtailable customers paying for a benefit that would not likely be realized until 2048 or beyond.

Q. But why is it appropriate for current CSR customers to receive a credit?

A. As I mentioned earlier, and in my direct testimony, the Companies' current generation resources were planned based the assumption that the Company's current CSR customers are a capacity resource. The savings from the curtailable load from the Company's current CSR customers are already built into the system. Therefore, LG&E's current CSR customers should continue to receive CSR credits. The fact that the current CSR load has already been built into the system is the primary reason, as explained earlier, that the Company is proposing to determine the level of the credits based on an embedded cost approach rather than using an avoided cost approach would result in lower credits.

Q. How do you respond to Mr. Pollock's comment that the decrease in the CSR credits violates the principle of gradualism?

A. It is unclear whether the principle of gradualism has any bearing on the CSR credit.

With curtailable service, the Company is, for all intents and purposes, purchasing a service from the curtailable customers. In exchange for curtailable service, the Company provides (or "pays") the customer a credit. Therefore, the CSR credit is unlike the rates for electric service that the Company charges other customers. In some respects, the option to curtail customers' load under CSR is not dissimilar from capacity purchases that the Company might make from third-party power suppliers. Just as it is the Company's responsibility to keep from overpaying third-party power suppliers for capacity reservations, it is LG&E's responsibility to ensure that the Company does not overpay CSR customers for curtailable service that the customers are providing, because ultimately LG&E's other customers end up paying for the CSR credits provided to the curtailable customers.

Nevertheless, the economic impact on the customers taking CSR service is also important. In most cases, these customers are extremely large, energy-intensive companies that compete in international markets. Power costs can certainly affect their ability to compete. The Companies' annual revenue from the 13 customers taking service under CSR on the combined LG&E and KU system is over $106 million. They employ more than 2,300 full-time workers, not counting any contract employees they may rely on. They are integral to their local economies. The Company is not blind to the benefits that these customers provide to the local economies and to the Company's other customers. From the perspective of LG&E's other ratepayers, the continuing presence of the CSR customers on LG&E's system certainly has a beneficial effect on the rates of other customers. Without the contributions to the fixed costs that are currently made by CSR customers, the rates to other customers would be higher. Likewise, any reductions in power sales to LG&E's CSR customers would put upward pressure on the rates charged to other customers.

Q. Therefore, what is your view on the level of the credits?

A. Looking only at embedded or avoided costs and the Companies' current planning assumptions, the current CSR credits are too high. The current CSR credit is $6.40 per kVA for transmission service and $6.50 per kVA for primary service. Based on LG&E's embedded cost methodology the credit would be $3.56 per kVA and $3.67 per kVA for transmission and primary service, respectively. Based on avoided costs, the credit would be between $1.36 to $3.27 per kVA, without considering the effect of losses. Using either an embedded approach or a marginal approach, the current CSR credits of $6.40 to $6.50 are overstated. The methodology that was used by the Company to calculate the credits is reasonable, particularly considering that an avoided cost methodology would generally support a lower level of credits.

But it is also important to consider the economic impact that reducing the CSR credits will have on the large customers taking service under the rider, precisely because impacts to those customer can have further effects on other customers and their rates over time. How to account for this impact is largely a matter of judgment. To avoid prejudging the issue, the Company proposed CSR credits based solely on an embedded cost approach (which results in credits greater than avoided costs). But there is a reasonable range of CSR credits for which one could plausibly argue using an embedded cost approach as a starting point.

C. PROPOSED RATCHETS FOR RATES TODS, TODP, RTS, FLS

Q. Please explain the proposed change to the Base Demand Charge ratchet.

A. The Company is proposing to increase the ratchet for the Base Demand Charge from 75% to 100%. The Company is not proposing to change the demand ratchets for the Peak and Intermediate Charges at this time.

Q. What is a "demand ratchet"?

A. A "ratchet" refers to a mechanism in which a percentage is applied to the monthly recorded demands in kW (or kVA where appropriate) for the previous 11 months for purposes of determining the billing demand for the current month. The word "ratchet" is a metaphor based on the tool or wrench – a ratchet – that tightens a bolt in one direction but will not loosen the bolt in the opposite direction.[38] With a 75% ratchet, for example, the billing demand for the current month is equal to the greater of (i) the metered demand for the current month or (ii) 75% of the maximum monthly demand for the previous 11 months. To illustrate the concept of a 75% ratchet, assume that a customer has the following recorded demands for the current month of May, 2017, and the 11 preceding months:

[38] The metaphor is not perfect because, unlike a mechanical ratchet, the Company's demand ratchet can "loosen" a year after setting an increased billing demand.

MONTH	YEAR	MEASURED DEMAND	75% OF MEASURED DEMAND
May (Current Mo)	2017	3,200	--
Apr	2017	3,400	2,550
Mar	2017	3,750	2,812
Feb	2017	4,100	3,075
Jan	2017	4,500	3,375
Dec	2016	4,200	3,150
Nov	2016	4,100	3,075
Oct	2016	3,800	2,850
Sep	2016	3,200	2,400
Aug	2016	3,900	2,925
Jul	2016	4,000	3,000
Jun	2016	3,900	2,925

TABLE 8

With a 75% ratchet, the *billing* demand for May, the current billing month, would be equal to the greater of 3,200 kW or 75% of the highest monthly demand for the previous 11 months. Since, in this example, the 75% of the highest demand during the previous 11 months was 3,375 kW (or 75% x 4,500 kW = 3,375 kW), the billing demand for May would be 3,375 kW.

Q. In this example, what would the billing demand for the Base Demand Charge be for May 2017 with a 100% ratchet, as proposed by LG&E?

A. The billing demand for May would be 4,500 kW (4,500 kW x 100 % = 4,500 kW). But it is important to keep in mind that the Company is not proposing a 100% ratchet on all three components of the demand charge. Rates TODS, TODP, RTS, and FLS have three demand components – a Base Demand Charge, an Intermediate Demand Charge, and Peak Demand Charge. The Peak and Intermediate Demand Charges would continue to have a 50% ratchet. The proposed demand charges for Rate TODP, for example, are as follows:

Peak Demand Charge	$ 6.86 /kW/Mo
Intermediate Demand Charge	$ 5.03 /kW/Mo
Base Demand Charge	$ 3.18 /kW/Mo

With LG&E's proposal, the Peak Demand Charge of $6.86 and the Intermediate Demand Charge of $5.03 would continue to reflect a 50% ratchet, and only the Base Demand Charge of $3.18 would be applied using a 100%. Therefore, the two largest demand components of Rate TODP – the Peak and Intermediate Demand Charges – will continue to be billed using a 50% ratchet. The smallest of the three components – the Base Demand Charge – would be billed using a 100% ratchet. Therefore based on a simple ratio, approximately 78.90% of the demand charges will continue to be billed on the basis of the 50% ratchet ([$6.86 + $5.03]/[$6.86 + $5.03 + $3.18] = 78.90%.) Therefore, the effective overall ratchet would be 60.55% (78.90% x 50% + (100% - 78.90%) = 60.55%). It is important to recognize that ratchets for large power customers in the 60% to 90% range are not uncommon in the industry. The overall effect of LG&E's proposed ratchets is within a typical range for many utilities.

Q. Briefly, why is it appropriate to apply a 100% ratchet to the Base Demand

Charge?

A. The Base Demand Charge covers the cost of delivering power to these large power customers. The customers taking service under Rates TODS, TODP, RTS and FLS are the largest customers served by LG&E. Because the Company must have sufficient distribution capacity to deliver power to these customers at all times, it is appropriate to determine the demand charge for delivery service based on the customer's maximum demand for the year. The Company's production demand costs (i.e., the cost of generation capacity) are recovered through the Peak and Intermediate Demand Charges, which will continue to include a 50% ratchet.

Q. What are the intervenors' positions regarding the proposed 100% ratchet for the Base Demand Charge?

A. KIUC supports the ratchet. KIUC's witness Baron offers the following testimony:

> The Commission should accept the Companies' proposed increase to the demand ratchet for the base demand charges for Rate TOD-S, TOD-P, RTS, and FLS. This proposal is reasonable and reflects cost causation.[39]
>
> The Companies' argument in support of this rate design change is that the base demand charge is designed to recover distribution and transmission related fixed demand costs that are incurred on the basis of maximum rate class demands and maximum customer demands. As such, *a 100% ratchet tied to a customer's maximum demand in the current month or the preceding 11 months more closely follows cost, than the current 75% ratchet*.[40]

[39] Baron testimony at page 7, lines 14-17. Emphasis added.
[40] Baron testimony at page 38, lines 12-16. Emphasis added.

Wal-Mart's witness seems to oppose the elimination of the Company's Supplemental or Standby Rider ("Standby Rider") and recommends that the Commission reject the 100% ratchet for the Base Demand Charge. Wal-Mart's Witness, Mr. Tillman, states that he is "concerned the proposed solution [eliminating the Standby Rider and implementing a 100% ratchet for the Base Demand Charge] ignores the benefits of distributed generation and implements disincentives to customers' demand management initiative … Additionally, the existence of a 100 percent demand ratchet sends a price signal that reduces the economic value of demand management measures, discouraging the deployment of demand management programs intended to increase system efficiency."[41]

Q. Is the Company justifying the demand ratchet based on the elimination of the Standby Service Rider?

A. No. While the demand ratchet is implemented in conjunction with the elimination of the Standby Rider, a 100% ratchet applied to transmission and distribution delivery costs is justified to all types of customers, not just those receiving standby service. Whether a customer is receiving standby service or standard (non-standby) service, the Company must deliver power to the customer. The purpose of the proposed ratchet is not to discourage distributed generation, but rather, to implement a rate structure that is equitable to all customers. Whether a customer has its own generator and falls back on the Company for power when the customer realizes a forced outage or the customer

[41] Tillman testimony at page 30, lines 10-18.

is a low load factor customer that only purchases power occasionally from the Company, from a power delivery perspective, the two customers would be the same. The reason that LG&E is proposing a 100% ratchet for transmission and distribution delivery costs is to ensure that low load factor customers that *only purchase power occasionally* are not subsidized by high load factor customers that *purchase power on a regular basis*. Without a 100% ratchet, customers that purchase power infrequently would be subsidized by other customers. By eliminating the Standby Rider and serving customers with distributed generation on the same rate schedule as low load factor customers, as well as high and medium load factor customers, the Company will be offering service to all large customers on a non-discriminatory basis.

Q. Please explain how a low load factor customer is similar, from an operational and capacity perspective, to a customer that self generates and only occasionally falls back on the Company to supply backup power.

A. Consider Customer A receiving service from the Company that owns a 10 MW generator that is designed to operate continuously but with a 10 percent random forced outage rate. Statistically, this means that the generator will be forced out 10 percent of the time. If the outages are random, the generator will be expected to be forced offline on average 73 hours per month. For a 10 MW generator, the Company would provide on average 10 MW of standby power for 73 hours per month. Consider Customer B that operates some sort of machine – a large metal shredding machine for example -- that draws 10 MW of power but is only used infrequently. Assume that the customer only needs to shred metal when a certain amount of scrap metal is accumulated, which will again occur randomly. Assume further, that the scrap metal machine operates on average 73 hours per month. For a 10 MW metal shredder, the Company would provide on average 10 MW of power for 73 hours per month. From a distribution delivery perspective, there is no difference in the distribution and transmission delivery capacity needed to serve the two loads. The Company must be in a position to deliver 10 MW of power whenever the customer needs it. Therefore, it is appropriate to bill both customers a delivery demand charge for 10 MW of delivery capacity whether the customer needs 10 MW in a month or not. In both cases, the Company will have installed sufficient distribution and transmission capacity to deliver the power to the customer each and every month. It is thus appropriate for both customers to pay the same monthly fixed demand costs related to the 10 MW of capacity necessary to deliver the power to the customers.

Q. Do you agree with Mr. Tillman's claim that the proposed ratchet for the Base Demand charge will discourage the deployment of demand management programs intended to increase system efficiency?

A. No, just the opposite effect should occur. As demonstrated earlier, the Company is not proposing to modify the ratchets applicable to the two largest demand components of Rates TODS, TODP, RTS and FLS. The ratchets for the Peak and Intermediate Demand Charges, which for Rate TODP make up 78.9% of the total demand charges will remain the same. Importantly, the Peak and Intermediate Demand Charges only apply to demands that are recorded during the peak and intermediate time-of-day periods. Therefore, if customers can reduce their demands during these periods in subsequent time-of-day periods, then they will only be held to a 50% ratchet, just as they are currently. Nothing has changed for these two demand charges. The implementation of the 100% ratchet will encourage customers to monitor their maximum demands more carefully to insure there aren't unnecessary peaks in their loads. Ultimately, the Company must have sufficient delivery capacity to serve the customers maximum demand, whenever it occurs. If customers can reduce their maximum demands, then it would be possible for the Company to operate with less delivery capacity, thereby creating greater efficiency. Under the Company's proposal, customers would pay the costs of the line and transformer capacity installed to deliver power to *their facilities*, instead of shifting those costs onto other customers.

Q. Are you saying that the Company's proposed ratchet for the Base Demand Charge is primarily about eliminating subsidies between customers?

A. Yes. It is important to keep in mind that the rates are designed to collect the same revenue regardless of the Base Demand Ratchet percentage. The test-year revenue would be the same for these rate classes regardless of the ratchet. The reason for this is that the billing demands used to design the Base Demand Charges are higher with a 100% ratchet than with a 75% ratchet. Therefore, to the extent that a 75% ratchet were to be used, the billing demands for the proposed rate would be lower and the demand charge would be correspondingly higher. Therefore, within rounding, the effect of the Company's proposed ratchet is revenue neutral for individual rate classes. To illustrate this, the following Rebuttal Exhibit WSS-6 shows what the billing demands, demand charge and revenues for the Base Demand Charge would be for a 75%, 80%, 90%, and

100% ratchet. As can be seen from this exhibit, the Base Demand Charge revenue collected under any of these ratchets would be almost the same. Therefore, the Company is not collecting more revenue from any rate schedule with the 100% ratchet proposal, the Company is simply providing better assurance that the large power customers who place costs on the system are the ones paying those costs.

D. SPECIAL SCHOOL RATES PROPOSED BY KSBA

Q. Is the KSBA proposing a new set of special school rates?

A. Yes.

Q. Please describes KSBA's proposal.

A. KSBA is proposing to create two new rate schedules for public schools – Rate P-12 Public School – Time of Day Service and Rate P-12 Public School – Power Service. KSBA's Rate P-12 – Time of Day Service is modeled after the Company's standard large power rate schedules Rates TODS and TODP, except KSBA's proposed rate would offer deep discounts for schools. KSBA's Rate P-12 – Power Service is modeled after the Company's Power Service Rate PS, except KSBA's proposed rate would again offer deep discounts for schools. KSBA is proposing to allow public schools currently served under Rates TODS, TODP, and PS to move to deeply discounted special public school rates.

Q. Does the Company favor offering rates targeted to specific customer segments based on the type of commercial or industrial end use?

A. No. The Company has moved away from offering rates targeted to specific types of commercial and industrial customers. In fact, the trend in the industry is to move away from such special-interest rates. It has been the Company's objective to develop cost-based rates that are applicable to all types of customers, regardless of their load profile. This is one of the reasons that the Company has been extending its time-of-day rate offerings to apply to more customers. With the implementation of advanced metering systems (AMS), the Company will be able to offer time-of-day rates to far more customers. In the past, offering time-differentiated three-part rates to a large number of customers would have been cost prohibitive. With a properly designed multi-part rate there is no need to offer rates targeted to specific customer segments, such as coal mines, public schools, private schools, churches, prisons, irrigation pumps, grain drying facilities, ball field lights, asphalt plants, chemical companies, automobile manufacturers, steel plants, etc. all of which might have different load profiles. Over the years, I have seen special rates for all of these customer types, but most utilities are trying to move away from offering special rates targeted to specific industries or special interests.

Q. Would offering special rates for schools create an administrative burden for the Company?

A. Yes. LG&E does not have special coding for public schools, nor does it have information that is readily available to determine whether a school would qualify for KSBA's proposed Rate P-12 – Power Service or Rate P-12 – Time of Day Service. Therefore, it is impossible for the Company to validate the billing determinants that were used by the KSBA to develop the consumption analysis shown in RLW Exhibit

4 to Mr. Willhite's testimony. In its response to data requests, the KSBA failed to provide customer identification codes which made it impossible for the Company to validate the billing determinants included in RLW Exhibit 4. Furthermore, the consumption analysis was based on billing data from randomly selected schools from Fiscal Year 2016 (i.e., the 12 months ended June 2016). Thus, the consumption analysis used by Mr. Willhite to perform his cost of service study and his rate analysis does not correspond to the forecasted test year of the rate case.

Q. Has the KSBA demonstrated that public schools have a unique load profile that would warrant a special rate?

A. No. The KSBA witness claims that peak demands for public schools occur outside of the Company's peak periods, but the load patterns of schools are not significantly different from commercial businesses and manufacturers, particularly manufacturers with one-shift operations. Public schools, office buildings and manufacturers will typically realize their maximum demands from 6 A.M. to 2 P.M, during the same time-frame as public schools. While I acknowledge that the load patterns for public schools are different from residential customers, they aren't materially different from office buildings and many other types of manufacturers. Certainly, the load patterns for public schools do not justify the creation of two new special rates.

Q. Has the KSBA demonstrated that *public* schools have load profiles that differ from *private* schools?

A. No. Again, there is no justification for a special rate for *public schools*. KSBA's proposed public school rates would be unduly discriminatory to *private schools* and numerous other groups of customers.

Q. Does the Company's load data support the KSBA's position that the maximum demands for schools occur outside of the Company's peak and intermediate load periods.

A. No. KU and LG&E provided detailed support in Case Nos. 2009-00548 and 2009-00549 for the selection of the peak and intermediate periods used in its large power time of day rates (Rates TODS, TODP, RTS and FLS). The load data used to define the peak and intermediate time-of-day periods were based on an analysis of the Companies' system loads. During the summer months, the Company's peak period is defined as the period between 1 P.M. and 7 P.M. During the winter months, the Company's peak periods is defined as the period between 6 A.M. and 12 Noon.

Based on the Company's load data for public schools, the maximum demand for public schools occur during exactly the same time frame as non-schools served under the Company's large commercial and industrial rates schedules (Rates PS, TODS, TODP, RTS and FLS). During both winter and summer months, schools will peak between 6 A.M. and 2 P.M. For example, during July, both schools and non-school commercial/industrial customers realize their maximum demands at 1:00 P.M. During January, public schools realize their maximum demand at 9:00 A.M.; whereas, non-school commercial/industrial customers realize their maximum demands one hour later at 10:00. Therefore, there is no basis to Mr. Willhite's claim that school load is fundamentally different from non-school commercial/industrial load.

Q. Did you review Mr. Willhite's cost of service study and rate analysis?

A. Yes.

Q. Do Mr. Willhite's analyses provide a sound basis for supporting the introduction of two new special rates?

A. No. In developing his proposed rate, Mr. Willhite prepared a consumption analysis (RLW Exhibit 4) and a cost of service study. In developing his cost of service study, Mr. Willhite modified the Company's LOLP cost of service study by adding a new column in the class allocation section of the study to represent his proposed school rates. His consumption analysis was compiled from billing data for a select number of public schools. There are numerous problems with Mr. Willhite's rate analysis and his cost of service study rendering them useless in supporting the development of his proposed special rates for public schools. In performing his cost analysis, Mr. Willhite makes assumption upon assumption upon assumption. Listed below are some of the problems:

(1) As mentioned earlier, the billing data used in Mr. Willhite's consumption analysis (RLW Exhibit 4) was assembled from historical data for a somewhat arbitrary group of schools. LG&E's consumption analyses in this rate case were developed based on forecasted billing determinants which assumed normal weather patterns. *All* of the proposed rates and charges proposed by LG&E in this proceeding were based on forecasted costs and billing determinants. Mr. Willhite made no attempt to adjust his historical billing determinants to match the forecasted billing determinants developed by the Company for the other rate schedules in this proceeding. Mr. Willhite's consumption analysis for his new school rate, which is based on

historical kWh and demand data, will not be consistent with or otherwise match the forecasted test year and will thus violate the "matching principle".

(2) In his consumption analysis (RLW Exhibit 4), Mr. Willhite fails to remove base Environmental Cost Recovery (ECR) revenues from base revenues. In the Company's cost of service study, and in the determination of revenue requirements in this proceeding, base ECR revenues were removed. These are ECR revenues for ongoing projects that have been transferred to base rates. This can be seen in pages 3-15 of Schedule M-2.3-E of the Company's filing requirements in this proceeding. Because ECR costs were removed from the Company's revenue requirement, the Company also removed ECR revenues from base revenues. Mr. Willhite, however, failed to remove ECR revenues for his new Schools rates from base revenues. To demonstrate this I have included the consumption analysis for Rate PS-Secondary from Schedule M-2.3-E of the Company's filing requirements as Rebuttal Exhibit WSS-7. As can be seen from this exhibit, the Company has removed base ECR revenues to calculate an amount labeled "Total Base Revenues Net of ECR". This is the amount that is included in the Company's cost of service studies, and this is also the amount that is used to determine the revenue deficiency in the case. I have included Mr. Willhite's consumption analysis as Rebuttal Exhibit WSS-8. As can be seen from Mr. Willhite's consumption analysis, in determining the revenue that he reflects in his cost of service study, he skips the step of removing base ECR revenues from revenues that he carries forward into his cost of service study. Mr. Willhite's failure to remove base ECR revenues from base revenues for his proposed school rate has the effect of

overstating the rate of return for the class in his cost of service study.

(3) As explained in his testimony, Mr. Willhite estimated the LOLP allocator for his school rate by prorating the LOLP allocator for KU's All Electric Schools (Rate AES) on the basis of relationship *for a single hour* between the estimated summer CP for the School Class to AES summer CP.[42] This is an inaccurate and flawed method for calculating the LOLP allocator for his new school class. In the Company's cost of service study, the LOLP allocator for AES is *not* determined based on the summer CP (a single peak hour), but, rather, by calculating the load weighted LOLP for each hour of the year. Therefore, Mr. Willhite's method of extrapolating the LOLP allocator based solely on a CP for one hour is not consistent with the methodology used in the Company's study. Furthermore, because school load is lower during the summer months, his short-cut approach has the effect of overstating the rate of return for his new school class.

(4) Mr. Willhite extrapolates the load relationship for schools taking service under KU's Rate AES to LG&E's schools currently taking service under Rate PS, TODS, and TODP. The load profile for the public schools currently taking service under LG&E's Rate PS, TODS, and TODP are likely not comparable to the schools taking service under KU's Rate AES.

(5) In his cost of service study, Mr. Willhite failed to differentiate between public school customers served at primary voltages and those served at secondary

[42] Willhite testimony at page 6, lines 1-7.

voltages. He grouped primary and secondary voltage customer together into a single rate class for the cost of service study even though the costs of providing service to primary and secondary customers are quite different.

Q. What is your recommendation regarding KSBA's proposed special rates for public schools.

A. It is my recommendation that the Commission reject the KSBA's proposal. The KSBA has not provided sound cost justification for offering deeply discounted special rates for public schools currently served under Rates PS, TODS, and TODP.

E. SPECIAL 34.5 KV RATE PROPOSED BY THE DOD

Q. Is the DOD proposing a special rate discount for customers served at 34.5 KV voltage?

A. Yes. The DOD's witness, Mr. Selecky proposes to provide a special rate discount equal to 25% of the Base Demand Charge for customers taking service at 34.5 kV voltage.

Q. How many retail customers are served at 34.5 kV voltage?

A. One, the customer represented by the DOD in this proceeding.

Q. Is there a sound basis for the DOD's proposed discount for customers taking service at 34.5 kV?

A. No. In arriving at the 25% discount in the Base Demand Charge Mr. Selecky subjectively reduces the portion of the Base Demand Charge related to distribution-related costs by 50%, with no cost justification whatsoever. Because 51.94% of the Base Demand Charge is related to distribution costs, applying 50% to the 51.94% figure results in a 26% discount, per Mr. Selecky's calculations. He then rounds the 26% down to 25% to arrive at his proposed discount.

Q. Is there a cost basis for the 50% reduction in distribution costs used by Mr. Selecky?

A. No. Mr. Selecky provides no cost analysis to support the 50% reduction. The 50% is based on a subjective determination made without examining the physical infrastructure, let alone the actual cost of the infrastructure, that is in place to provide 34.5 kV service to the customer. In data requests, the DOD did not request descriptions of the LG&E's 34.5 kV system or electrical diagrams for the 34.5 kV system.

Q. Please describe LG&E's 34.5 kV system that serves the DOD customer.

A. The DOD customer is served by three 34.5 kV circuits, which are located entirely on the customer's property and serves no other customers. The 34.5 kV circuits serving the DOD customer consist of 17.8 miles of primary distribution lines. There is no other customer on LG&E's system for which this amount of distribution facilities has been installed to provide service.

Furthermore, to provide contingency for the loss of any one circuit, the system serving the DOD customer was designed and built to a much higher standard than usual. The DOD customer pays no additional charges to receive the benefits of this contingency. Following the ice storm of 2009 and in anticipation of growing load, extensive improvements were made to these three circuits including major reconductoring in multiple areas and the installation of new switches and other equipment.

The DOD customer taking service at 34.5 kV is the only customer on LG&E's system for which any significant Company-owned distribution facilities are located on the customer's property and behind the customer's meter. With all other large power customers, LG&E connects service as near as practicable to the customer's property line, and the customer is responsible for maintaining all electrical facilities located on its property. For example, LG&E provides primary service to several university campuses in its service territory. With the university campuses, the Company provides primary service as close as possible to universities' property lines. This is not the case with the DOD customer taking service at 34.5 kV. With the DOD customer, LG&E owns the 34.5 kV primary distribution network on the DOD customer's property. LG&E is also responsible for maintaining the distribution facilities on the customer's property, repairing the facilities in the event of a storm, and upgrading the facilities for changes in load.

Q. Since LG&E does not break out its rate for any other primary voltage, then why would it be appropriate to break it out for 34.5 kV voltage service?

A. It is not appropriate to offer a special rate for 34.5 kV service, especially at a discounted rate. All primary voltage costs are included in a single group in the Company's cost of service study. Decades ago, LG&E began defining 34.5 kV service as primary voltage and accounting for the costs of the 34.5 kV system as distribution costs. Because the costs of the 34.5 kV system are reflected as primary voltage costs, LG&E's other primary voltage customers are required to pay for costs of the DOD's extensive 34.5 kV system that they are not utilizing. Mr. Selecky's comment therefore cuts both ways.

While the DOD customer is not using the 13.8 kV, 7.2/12.47 kV, or 2.4/4.160Y kV systems, other primary customers aren't using the extensive 34.5 kV system that has been installed to serve the DOD customer. But other customers are still paying for the costs of the 34.5 kV system as a result of the costs of the 34.5 kV system being included in with the total. Therefore, Mr. Selecky's observation cannot justify providing a discount for the DOD customer served at 34.5 kV, particularly considering that a detailed engineering analysis would likely support a higher charge for 34.5 kV service.

Q. Does LG&E maintain detailed accounting records for each primary voltage level?

A. No. Ultimately, the Company does not have detailed accounting records breaking out the accounting costs for each primary voltage, including the costs related to its 34.5 kV system. Therefore, any attempt to develop a separate charge for the 34.5 kV service would need to be based on a *detailed* and *costly* engineering analysis. At this point, neither the DOD nor LG&E has performed such an analysis, and it is not LG&E's recommendation that one be performed.

Q. What is your recommendation regarding the DOD's proposal?

A. There is no justification for providing a discount for Rate TODP customers served at 34.5 kV voltage. It is my recommendation that the Commission reject the DOD's proposal. However, if the Commission determines that the issues raised by the DOD warrant the Company performing a detailed engineering study to determine the cost of the distribution facilities that have been installed to serve the DOD customer, then it would be my recommendation that the cost of such study be paid for by the DOD customer.

F. OTHER RATES AND CHARGES

Q. The Company proposed a number of changes in its miscellaneous charges. Please discuss those charges.

A. The Company proposed to add an Unauthorized Reconnection Charge to its electric and gas tariffs. The Company also proposed to increase it Redundant Capacity Charge. The intervenor witnesses did not address these charges. The Company also proposed to broaden its pole attachment rate (Rate PSA) to include not only charges for cable television attachments but also charges for telecommunication wireline and wireless facilities that are attached to LG&E's poles and cable television and telecommunication wireline facilities using the Company's underground electric infrastructure. The carrying charges that supported the underlying charges were addressed in my direct testimony. None of the intervenor witnesses offered any criticisms of the carrying charge calculations that supported the proposed charges for Rate PSA, though the Kentucky Cable Television Association ("KCTA") and AT&T contest the amount of the wireless attachment charge based on the amount of pole space needed for such attachments, which John K. Wolfe addresses in his rebuttal testimony. The other issues raised by the KCTA and AT&T, which principally concern operational issues, are also addressed in the rebuttal testimony of Mr. Wolfe.

V. GAS COST OF SERVICE STUDY

Q. Did any of the intervenor witnesses comment on LG&E's gas cost of service study?

A. Yes. Louisville Metro witness Pollock stated that based on his review "the structure and methodology used by LG&E generally comport with accepted practice."[43] Mr. Pollock goes on to state:

> [S]ince cost causation is also related to how natural gas is used, both the timing and rate of gas consumption (i.e., demand) are critical. Consistent with the obligation to serve and to ensure reliability, the LDC must purchase sufficient gas supply to meet the maximum needs of its sales customers. The LDC must also construct the required distribution mains and other facilities to meet the contribution to the maximum demand that can potentially be placed on the system by the classes or by the customers within the classes.[44]

I am in full agreement with Mr. Pollock's remarks.

The AG witness takes an altogether different position from that of Mr. Pollock. Mr. Watkins proposes to allocate the cost of mains based on a Peak and Average approach. In his version of the Peak and Average methodology, Mr. Watkins allocates 50% of the cost of distribution mains on the basis of average demand (commodity) and 50% on the basis of maximum demand. He claims that the Peak and Average methodology "recognizes each class's utilization of the Company's facilities throughout the year yet also recognizes that some classes rely upon the Company's facilities (mains) more than others during peak periods."[45]

Q. Do you agree with the AG witness's Peak and Average approach?

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[43] Pollock testimony at page 56, lines 3-4.
[44] Pollock testimony at page 58, lines 7-13.
[45] Watkins testimony at pages 69-70.

A. No. Mr. Watkins develops an allocation for mains based on an arbitrary 50/50 split between demand and average demand (commodity). His 50/50 split is not only subjective, it is not grounded on principles of cost causation. As Mr. Pollock explained, LG&E "must also construct the required distribution mains and other facilities to meet the contribution to the maximum demand that can potentially be placed on the system …."[46] Average demands have nothing to do with the size of the mains (pipe) installed by LG&E. As Mr. Pollock explains, mains are sized to deliver the natural gas to customers during periods of maximum demands which, for LG&E's gas operations, occur during the coldest days of the year. Not only does Mr. Watkins' Peak and Average methodology for allocating distribution mains fail to reflect cost causation on LG&E's gas distribution system, it is also grossly inconsistent with the methodology that he uses in his proposed electric cost of service study.

Q. Please explain how Mr. Watkins' Peak and Average methodology for his gas study is inconsistent with his electric cost of service study.

A. In its gas cost of service study, LG&E classified distribution mains as either customer- or demand-related using the zero-intercept methodology. Costs classified as customer-related are then allocated to the customer classes based on the number of customers for each customer class, and costs classified as demand-related are then allocated on the basis of maximum class demands. This is the same methodology used to classify overhead and underground conductor in the electric cost of service study. Like LG&E,

[46] Pollock testimony at page 58, lines 10-12.

Mr. Watkins used the zero-intercept analysis to classify secondary conductor in the cost of service study that he performed for LG&E's electric operations. For a gas utility, mains serve *exactly the same function* as overhead conductor and underground conductor for an electric utility – they both transport the product (electric energy or natural gas) to the customer. Mains and conductors are also similar in another key respect – the capacity to transport the product varies in direct proportion to the size (cross-sectional area) of the main or the conductor. It is for this reason that the zero-intercept methodology has been used for over 30 years to classify mains on the gas side of LG&E's business and to classify overhead and underground conductor on the electric side of the business. If it is appropriate to use a zero intercept analysis for classifying secondary distribution lines for the electric study, then it must also be appropriate to use a zero intercept analysis for classifying gas distribution mains.

Mr. Watkins' gas cost of service study is fundamentally at odds with his electric cost of service study. In his gas cost of service study, Mr. Watkins' does not allocate any of the cost of mains on the basis of the number of customers, even though in his electric cost of service study he classified a portion of transformers and a portion of secondary distribution lines as customer related. As with secondary conductors, LG&E installs gas mains to connect new customers regardless of size of the customers. Certainly, LG&E's main extension policy speaks of a minimum revenue requirement for a customer to be connected, but regardless of the size of the customer, LG&E must extend pipe to serve the customer. The Company must extend pipe regardless of whether the customer uses a minimal amount of gas or a large amount of gas.

Therefore, there is a fixed cost of serving customers regardless of how much gas the customer uses. By allocating main costs 50% on the basis of demand and 50% on the basis of annual usage, Mr. Watkins' allocation methodology for gas mains fails to recognize that there is a fixed component of main costs that does not vary with the annual consumption of natural gas by customers.

Furthermore, in his electric cost of service study, he does not allocate any distribution costs on the basis of annual energy consumption. Yet, in his gas study, he allocates 50% of the cost of mains on the basis of annual gas consumption. There is no cost justification whatsoever for allocating any portion of the distribution system on the basis of annual gas consumption. Gas mains are sized to meet maximum demand, not average annual usage.

Q. Has the zero intercept methodology traditionally been used by LG&E to classify distribution mains?

A. Yes. The zero intercept methodology has been used by LG&E for at least 30 years.

Q. Has the Commission found the zero-intercept methodology to be reasonable in gas cost of service studies?

A. Yes. The Commission has found the zero-intercept methodology to be reasonable in numerous rate cases, including LG&E's last rate case for which a settlement agreement was not reached by the parties – Case No. 2000-080, Order dated September 27, 2000. Furthermore, NARUC's *Gas Distribution Rate Design Manual*, June 1989, identifies the zero intercept approach as a standard methodology for classifying gas distribution costs.[47]

Q. What other criticisms do you have of Mr. Watkins' Peak and Average Methodology?

A. The Peak and Average Methodology allocates a portion of mains on the basis of demand and a portion on the basis of Mcf sales, and none on the basis of customers. While customers' maximum demand and the number of customers a utility serves has a direct impact on a utility's distribution costs, including the cost of mains, the annual quantity of gas sold by a utility has no effect on the cost of mains. From a distribution planning perspective, the installation of distribution mains is unaffected by the amount of gas sold on an annual basis to its customers. A gas utility installs pipe to reach its customers and to meet the peak load conditions of those customers. As long as the maximum demand requirements do not change, increases or decreases in annual throughput volumes do not have any impact on a utility's distribution costs, particularly the cost of mains. Because annual Mcf sales (or throughput volumes) do not have any effect on LG&E's investment in distribution mains, annual Mcf sales should not be used to allocate the cost of distribution mains. In its Order in Case No. 2000-080, the Commission specifically rejected a cost of service study that allocated a portion of mains on the basis of Mcf sales. Even though it has been recommended on numerous

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[47] Although NARUC's *Gas Distribution Rate Design Manual* also mentions the Peak and Average Methodology, the manual indicates on pp. 27-28 that it is a "compromise" methodology adopted because it "tempers the apportionment of costs between high and low load factor customers."

occasions, to the best of my knowledge, the Commission has never approved a cost of service study that allocated the cost of distribution mains on the basis of Mcf sales.

Q. What is your recommendation regarding the gas cost of service study?

A. It is my recommendation that the Company's cost of service study be used as a guide for developing gas rates in this proceeding. The AG's proposed cost of service study does not reflect cost causation and should be rejected.

VI. ALLOCATION OF THE GAS REVENUE INCREASE

Q. What are the positions of the intervenor witnesses regarding allocating the gas revenue increase?

A. The AG witness proposes an alternative allocation of the revenue increase that considers both the Company's cost of service study and the AG's cost of service study, which uses the Peak and Average methodology to allocate the cost of distribution mains. For the four major rate classes (Rates RGS, CGS, IGS, and FT), the AG's proposal is not significantly different from LG&E's proposal, except for Rate FT. Under Mr. Watkins' proposal, Rate FT would be assigned a higher increase.

Louisville Metro proposes to assign all of the gas increase to residential customers. Mr. Pollock relied on the Company's cost of service study to make this recommendation.

Q. Do you have any comments on the AG's proposed allocation of the revenue increase?

A. Yes. The AG's proposal is not significantly different from the Company's proposal.

Although Mr. Watkins' percentage increases are calculated based on revenues excluding all adjustment clause revenues and LG&E's percentage increases are calculated on revenues including all adjustment clause revenues, LG&E and AG's proposals are not as different as they might appear by glancing at the percentage increases proposed by LG&E and the AG. For the major rate classes, the only significant difference between the Company's proposal and the AG's is for Rate FT. Mr. Watkins assigned a 7.73% increase to Rates RGS, CGS and FT based on Base Rate Revenue (*excluding* all adjustment clause revenues, as in the format presented by the AG).

Although Mr. Watkins does not provide a detailed explanation for why he used the same percentage increase for all three of these classes, his reason for assigning a higher percentage increase to Rate FT than what the Company proposed appears to be related to the methodological differences between the AG's cost of service study and the Company's cost of service study. Mr. Watkins used a Peak and Average Methodology for allocating the cost of distribution mains, whereas LG&E used a zero-intercept methodology which has been approved by the Commission in prior rate cases. As a result of this methodological difference, the AG's cost of service study shows a lower rate of return for Rate FT than the Company's cost of service study. But as discussed earlier, the Peak and Average methodology is not an accurate measure of the cost of providing service. Furthermore, the Peak and Average methodology is not consistent with cost of service methodologies that the Commission has found to reasonable.

Q. Do you agree with Mr. Watkins' proposal to assign a higher increase to Rate FT?

A. No. As I have said, Mr. Watkins' Peak and Average methodology is unsound. But I have other concerns as well. Customers taking service under Rate FT are typically large industrial or commercial customers. Because of their large natural gas usage, these customers have greater options to secure alternative fuel supplies than customers served under Rates RGS, CGS, and IGS. For example, Rate FT customers may also be large enough to consider options such as by-passing LG&E for another pipelines. Loss of revenues under Rate FT will result in shifting fixed costs to other customers. Also, having a competitive firm transportation rate could induce customers to add gas load or locate their operations in LG&E's service territory. Recovering revenue from Rate FT customers helps defray LG&E fixed costs which would otherwise be recovered from LG&E's gas sales customers.

Q. Do you have any other comments on the AG's proposed allocation of the revenue increase?

A. Yes. I disagree with Mr. Watkins' proposal with respect to Rate AAGS. LG&E proposed a rate decrease for Rate AAGS, whereas the AG witness proposes to leave the rate at the current level. The need to decrease the rate is necessitated by the increased Basic Service Charge resulting from transferring the Gas Line Tracker ("GLT") revenues into base rates. Because the GLT revenues were collected as a customer charge, the GLT transfer resulted in a customer charge of $2,838.87, which far exceeds the $100 monthly customer cost that can be supported by the cost of service study. Because of the difference between the current customer charge and the customer cost that can be supported by the cost of service study, the rate cannot be rebalanced without reducing the overall revenue to this class. While I do not disagree with Mr. Watkins' general position that "there should not be any rate reductions when overall revenues are increased in rates,"[48] the current customer charge level for AAGS necessitates a rebalancing of the rate that cannot be accomplished without a revenue reduction.

Q. Do you agree with Louisville Metro's proposal to assign all of the revenue increase to residential customers?

A. No. I do not believe that the residential rate of return of 5.08% for Rate RGS compared to the rate of return of 7.32% for Rate CGS and 11.00% for Rate FT justifies assigning all of the increase to residential customers. While I agree that the Company's proposal represents only a small movement toward the elimination of subsidies, Louisville Metro's proposal would result in an increase to residential gas customers of 13.4% which, in my opinion, is too high.[49] Considering the overall percentage increases for gas and electric services in this proceeding, I would recommend against assigning an increase of more than 10% to any major rate class.

[48] *Id.* at page 77, lines 24-25.

[49] Mr. Pollock's percentages are calculated on the same basis as LG&E's, whereby the increases are calculated on revenues including all adjustment clause revenue.

VII. GAS RATE DESIGN

A. RESIDENTIAL BASIC SERVICE CHARGE

Q. What is LG&E's current customer charge for Residential Gas Service (Rate RGS)?

A. Considering both the Basic Service Charge and amount of the GLT LG&E proposes to transfer to base rates ($5.70), the monthly customer charge for Rate RGS is effectively $19.20, which is the current Basic Service Charge of $13.50 per month plus the GLT amount be transferred of $5.70 per month.

Q. What Basic Service Charge has the Company proposed?

A. LG&E is proposing a Basic Service Charge of $24.00 per month, which corresponds to an effective increase in the customer charge of $4.80 per month ($24.00 - $19.20 = $4.80). The Company's proposed customer charge is based on unit costs from LG&E's gas cost of service study.

Q. What is the AG proposal regarding the Basic Service Charge.

A. Mr. Watkins recommends leaving the Basic Service Charge at $13.50.

Q. Do you agree with his recommendation?

A. No. Mr. Watkins is effectively proposing to reduce the current customer charge from $19.20 to $13.50. He failed to consider the fact that the company is proposing to transfer GLT revenue requirements into base rates. The current customer charge is effectively $19.20, not $13.50 as Mr. Watkins seems to claim. He purports that his cost analysis would only support a customer charge of $13.04, but his analysis excludes the customer cost component of gas mains from the analysis. I am unaware of any cost of service study approved by the Commission that does not classify at least some portion of gas mains as customer-related.

B. SUBSTITUTE GAS SALES SERVICE (SGSS)

Q. Please provide a description of LG&E's proposed Substitute Gas Sales Service (SGSS).

A. Rate SGSS is being proposed to provide substitute gas sales service for any customer who desires to receive firm sales service from LG&E in addition to gas received from other sources with which the customer is physically connected. This rate would apply to customers who normally purchase gas supply directly from a pipeline, from another local distribution company, or from a local producer but desire to rely on LG&E as an alternative or substitute supplier of natural gas. In its role as a substitute supplier, LG&E would maintain sufficient storage and distribution delivery capacity on its system to provide firm service to a customer under Rate SGSS, just as it would any other commercial or industrial sales customer. Rate SGSS is structured as a three-part rate consisting of (i) a Basic Service Charge, which is a fixed customer charge to be billed monthly; (ii) a Distribution Charge, which will be applied to monthly volumetric deliveries; and (iii) a Demand Charge, which will be applied to the customer's Monthly Billing Demand. The Company's proposed tariff defines the Monthly Billing Demand as follows:

> The Monthly Billing Demand shall be the greater of (1) the MDQ, or (2) the highest daily volume of gas delivered during the current month or the previous eleven (11) monthly billing periods. The term "day" or "daily" shall mean the period of time corresponding to the gas day as observed by the Pipeline Transporter as adjusted for local

time.[50]

A demand charge helps ensure that other customers are not subsidizing those customers who take substitution or backup service from LG&E. With a rate structure that includes only a volumetric charge but no demand charge, it is virtually impossible for the Company to recover the distribution capacity costs necessary to serve the customer. For customers substituting LG&E's gas supplies for those from other physical sources, and who might only fall back on LG&E on an *intermittent* basis, a rate that consists of only a fixed customer charge and a volumetric delivery charge does not allow the Company to recover the fixed demand costs that such customers place on the system. LG&E's proposed Rate SGSS includes a demand *ratchet provision* similar to what the Company is proposing for electric service Rates TODS, TODP, RTS, and FLS.

Q. Do any of the intervenor witnesses address Rate SGSS?

A. Yes. DOD witness Selecky addressed Rate SGSS in his direct testimony. Specifically, Mr. Selecky proposes to change the ratchet provision of Rate SGSS, as follows:

> Consistent with the establishment of billing demands for the electric tariffs, such as the TODP rate, I am proposing that a ratchet provision be established to determine the billing demand incurred during the previous 11 months. I am proposing that a ratchet provision of 50% be applied to the highest daily volume of gas delivered during the previous 11 monthly billing periods. The 100% ratchet provision is punitive and does not reflect any type of usage diversity by LG&E's customers.[51]

[50] LGE Filing Requirements (Tabs 1-45) – Part 1, P.S.C. Gas No. 11, Original Sheet No. 21.1, Rate SGSS.
[51] Selecky testimony at page 20, lines 15-19.

Q. Is Mr. Selecky's proposal consistent with the demand ratchet provision of TODP?

A. No. As with Rates TODS, RTS, and FLS, Rate TODP includes three demand charge components – Peak Demand Charge, Intermediate Demand Charge, and Base Demand Charge. The Peak and Intermediate Demand Charges are designed to recover fixed production costs, and the Base Demand Charge is designed to recover transmission and distribution delivery costs. The Demand Charge for gas service is essentially equivalent to the Base Demand Charge for electric.[52] Under the Company's current tariff, the Base Demand Charge, which recovers transmission and distribution delivery costs, currently incorporates a 75% ratchet, not a 50% ratchet as indicated by Mr. Selecky. For Rate TODP, only the Peak and Intermediate Demand Charges, which provide recovery of fixed production costs, incorporate a 50% ratchet. The Peak and Intermediate Demand Charges for Rate TODP are in no way analogous to the Demand Charge for Rate SGSS. Thus, if Mr. Selecky wanted to be consistent with the Company's current Rate TODP, then he should have proposed that a 75% ratchet be utilized for the Demand Charge for Rate SGSS. But LG&E is proposing to increase the ratchet provision of Rate TODP from 75% to 100%, which would be the same ratchet provision for Rate SGSS. Mr. Selecky did not challenge the proposed ratchet provision for TODP. To be consistent with the Company's *proposed* TODP, whose ratchet provision Mr. Selecky did not challenge, the ratchet provision of Rate SGSS

[52] For gas service, the analogue for the production fixed costs recovered through the Peak and Intermediate Demand Charges are the purchased gas demand costs recovered through the Company's Gas Supply Component (GSC).

should be 100%.

Q. Why is it appropriate to utilize a 100% ratchet for gas delivery service?

A. As with the electric system, LG&E's gas delivery system is sized to the maximum volumes of gas used by customers at any time. On LG&E's gas system, mains, regulators, and other equipment are sized to meet the maximum demands that individual customers place on the system. Therefore, it is appropriate to apply a demand charge to the maximum demand established by the customer. It is particularly important to have a high demand ratchet for Rate SGSS, under which service would be provided to customers such as the DOD customer whose usage is intermittent and who would only fall back on LG&E as a substitute supplier when customer fails to secure adequate gas supply.

Q. Mr. Selecky claims that the demand ratchet provision of Rate SGSS does not reflect any type of usage diversity. Does demand diversity matter for the portions of the distribution system providing service to individual customers?

A. No. The distribution system is sized to deliver gas to individual customers. For the DOD customer represented by Mr. Selecky, LG&E installed two 8-inch parallel pipelines directly from one of its storage facilities to provide service to the DOD customer. Each of these parallel pipelines span 3 to 4 miles and serves no other customer except the DOD. The Company installed two large gas regulator stations at its storage facilities solely to provide service to the DOD. The regulator stations include overpressure protection equipment, two gas regulator runs, piping, valves and electronic monitoring equipment. The Company has also installed two large metering stations, consisting of two six-inch orifice meters, one four-inch orifice meter, two rotary meters, regulation equipment, and electronic monitoring and control equipment. These facilities are sized solely to meet the DOD customer's maximum demands and no other customer. Therefore, with respect to the distribution facilities installed to serve the DOD, usage diversity is irrelevant, because there can be no diversity with respect to facilities that have been installed to serve a single customer.

Furthermore, there is little or no diversity between the DOD customer's usage and LG&E's system peak demand. Like most customers on LG&E's gas system, the DOD customer's usage requirements are driven by cold temperatures (high heating degree days). For example, during the last three winter peak seasons (Dec 2014 – Feb 2015, Dec 2015 – Feb 2016, Dec 2016 – Feb 2017), LG&E's maximum demand day occurred on February 19, 2015. LG&E maximum daily demand was 505,984 Mcf on February 19, 2015. The customer's maximum demand day during February 2015 also occurred on February 19, 2015. This indicates that on the peak day that occurred during the last three winter seasons, there was *zero diversity* between LG&E's system demand and the DOD customer's usage. The reason that both LG&E and the DOD experienced a peak on February 19, 2015, was because the mean temperature[53] on that day was 4°F, which was not only the coldest temperature during February 2015 but also the coldest day during the last three winter heating seasons.

Q. What is your recommendation regarding the Company's proposed ratchet

[53] "Mean temperature" is defined as the simple arithmetic average of the maximum temperature during the day and the minimum temperature during the day.

provisions for Rate SGSS?

A. It is my recommendation that the Commission approve the ratchet provisions for Rate SGSS. The provision is reasonable for gas sales service to customers whose purchases from LG&E are intermittent and who normally purchase natural gas from another provider but want to rely on LG&E as an alternative or substitute supplier of gas.

C. PROPOSED MODIFICATIONS TO RATE FT

Q. Please describe Firm Transportation Service Rate FT.

A. Rate FT is a rate available for firm transportation service on LG&E's gas system.

Q. JBS Swift witness Wallin claims that Rate FT does not allow electric generators of any type to use the rate. Is he correct?

A. No. Mr. Wallin states that, "The current FT rate schedule does not allow generators of any type to use the rate, preventing the use of third-party supplied natural gas."[54] Regarding electric generation, LG&E's Rate FT states as follows:

> Additionally, customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer's MDQ, are not eligible for service under this rate schedule.[55]

Therefore, Rate FT would allow a customer using gas solely to generate electricity for standby service to take service under the rate schedule.

Q. Mr. Wallin proposes that Rate FT be modified to allow generators scheduled to run with advance daily notice to take service under the rate schedule. Do you

[54] Wallin testimony at page 5, lines 5-6.
[55] LG&E's Gas Tariff, Sheet No. 30, Rate FT.

agree with his proposal?

A. No. Serving gas-fired generation loads under Rate FT creates problems associated with reliability and cost subsidies. Customers with electric generators particularly impose two significant system management risks on LG&E. First, by not being able to nominate daily gas requirements accurately, gas generators can create significant daily imbalances which LG&E must resolve. Second, generators can create hourly imbalances which LG&E must resolve. These customers use interstate pipeline transportation capacity that requires LG&E to take gas from the pipeline at uniform daily rates of flow (i.e., 1/24th of the daily nominated gas supply volume in a given hour). Any difference between hourly receipts from the pipeline and hourly deliveries to the customer are balanced by LG&E. That balancing requires LG&E to use either its on-system storage or the more flexible pipeline services held by LG&E for sales customers. Consequently, it is not appropriate to modify Rate FT to expand the use of the rate schedule for electric generation.

Mr. Wallin is proposing that Rate FT be modified so that JBS Swift can receive special treatment for a cogeneration concept that is, at best, preliminary. JBS Swift has not performed an engineering evaluation of the cogeneration concept, and has not made a decision as to whether it intends to use natural gas or diesel for a portion of the project.[56] Rate FT should not be modified simply to accommodate an engineering concept that JBS Swift is interested in evaluating.

[56] Wallin testimony at page 4, lines 7 and 15.

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Q. Did the operational and cost recovery problems associated with serving gas generators under standard rate schedules cause LG&E to introduce Distributed Gas Generation Service (Rate DGGS)?

A. Yes. LG&E implemented Rate DGGS in 2008 to provide service to electric generators. Qualifying electric generators are therefore eligible to take service under Rate DGGS. Mr. Wallin states that JBS Swift is evaluating a "blend of cogeneration and single-cycle generation." He indicates that the "cogeneration would be used on a regular basis while any single cycle generation (either natural gas or diesel) would be used as back-up to LG&E service and in the CSR program."[57] It is unclear at this point whether the single-cycle generator would be eligible for Rate FT. LG&E has not been provided with adequate details about JBS Swift's proposed gas-fired generation installation in order to determine whether or not LG&E's Rate DGGS is applicable or whether JBS Swift's gas requirements for it single-cycle generator would meet the current qualifications of Rate FT. If the generator is used solely for standby electric service, then it may be eligible for Rate FT. Significant details, such as hourly connected load; delivery pressure; minimum, maximum, and average gas load requirements; expected consumption; and delivery points are relevant in determining whether or not Rate DGGS is applicable or if service is even feasible using LG&E's existing infrastructure. Furthermore, if Rate DGGS is not applicable to the customer's circumstances, LG&E has indicated that it would be willing to discuss terms and

[57] Wallin testimony at page 4, lines 13-16.

conditions under a non-standard service arrangement (special contract) to provide separately metered gas transportation service for generation facilities owned and operated by the customer.[58]

Q. Please describe Rate DGGS and explain why it is the appropriate rate for electric generators.

A. Rate DGGS was originally approved by the Commission in its Order in Case No. 2008-252 dated February 5, 2009. Rate DGGS is a three-part rate consisting of a Basic Service Charge, a Demand Charge, and a Distribution Charge. The Distribution Charge is a volumetric charge per 100 cubic feet of gas and the Demand Charge is a charge per 100 cubic feet applied to the customer's monthly billing demand. In testimony filed in Case No. 2008-252, the Company witnesses explained that a three-part rate was designed to "compensate LG&E for having the necessary facilities in place to serve these loads"[59] and "will recover the fixed costs associated with new customers served under this rate irrespective of the actual amount of gas they may consume".[60] The need for serving electric generators under a three-part rate consisting of a customer charge, volumetric delivery charge and demand charge is as acute today as when it was first introduced in 2008. A three-part rate helps ensure that the cost of facilities installed to provide natural gas to electric generators are recovered from customers taking service under Rate DGGS and not shifted to other customers.

[58] *See* Response to JBS Swift & Co.'s Supplemental Requests for Information Dated February 7, 2017, Question No. 11.
[59] Direct Testimony of J. Clay Murphy, page 12, lines 11-12.
[60] Direct Testimony of William Steven Seelye, page 24, lines 4-5.

Q. Does this conclude your rebuttal testimony?

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF TRANSYLVANIA)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is a Principal of The Prime Group, LLC that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 4th day of April 2017.

____________________ (SEAL)
Notary Public

My Commission Expires:

11-17 2018

BENJAMIN D. UPTON II
NOTARY PUBLIC
Transylvania County, NC

Rebuttal Exhibit WSS-1

Analysis of LOLP Hours

(Exhibit is being provided in a separate file in Excel format)

Rebuttal Exhibit WSS-2

Cust Cost from the AG’s Electric Cost of Service Study

(Exhibit is being provided in a separate file in Excel format)

Rebuttal Exhibit WSS-3

Incremental Cost of Connecting a Res Elec Customer

(Exhibit is being provided in a separate file in Excel format)

Rebuttal Exhibit WSS-4

Avoided Cost Analysis based on CT in 2029

(Exhibit is being provided in a separate file in Excel format)

Rebuttal Exhibit WSS-5

Avoided Cost Analysis based on CT in 2048

(Exhibit is being provided in a separate file in Excel format)

Rebuttal Exhibit WSS-6

Impact on Billing Demand by Varying Ratchet Percent

(Exhibit is being provided in a separate file in Excel format)

Rebuttal Exhibit WSS-7

Elimination of Base ECR Revenue from Revenues

(Exhibit is being provided in a separate file in Excel format)

Rebuttal Exhibit WSS-8

Mr. Willhite's Failure to Remove Base Revenues

RATE P-12 PUBLIC SCHOOL (INTERIM)
POWER SERVICE
Secondary

	Bills	Kw	KWh	Present Rates		Proposed Rates	
Basic Service	1,404			$90.00	$126,360	$90.00	$126,360
Energy			122,503,014	$0.04071	$4,987,098	$0.04071	$4,987,098
Summer kW		204,411		$18.40	$3,761,162	$11.66	$2,383,150
Min Incr		1,005		$18.40	$18,487	$11.66	$11,714
Winter kW		233,046		$15.99	$3,726,400	$9.25	$2,155,350
Min Incr		3,330		$15.99	$53,242	$9.25	$30,795
Total					$12,672,749		$9,694,467

Mr. Willhite failed to remove Base ECR revenues from Total Revenues.

RATE P-12 PUBLIC SCHOOL SERVICE
TIME of DAY SERVICE
Secondary

	Bills	Kw	KWh	Present Rates		Proposed Rates	
Basic Service	48			$200.00	$9,600	$200.00	$9,600
Energy			5,434,039	$0.04049	$220,024	$0.04049	$220,024
Base kW		18,262		$4.60	$84,005	$2.47	$45,079
Min Incr Old		694		$4.60	$3,192	$2.47	$1,713
Min Incr New		3,951					
Inter kW		18,160		$5.10	$92,617	$2.97	$53,908
Min Incr		248		$5.10	$1,264	$2.97	$736
							$0
Peak kW		17,792		$6.74	$119,917	$4.61	$81,993
Min Incr		263		$6.74	$1,776	$4.61	$1,214
Total					$532,395		$414,266

Mr. Willhite failed to remove Base ECR revenues from Total Revenues.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	**)**	
UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2016-00370**
ADJUSTMENT OF ITS ELECTRIC	**)**	
RATES AND CERTIFICATES OF	**)**	
PUBLIC CONVENIENCE AND NECESSITY	**)**	

And

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN	**)**	**CASE NO. 2016-00371**
ADJUSTMENT OF ITS ELECTRIC	**)**	
RATES AND CERTIFICATES OF	**)**	
PUBLIC CONVENIENCE AND NECESSITY	**)**	

REBUTTAL TESTIMONY OF

JOHN J. SPANOS

ON BEHALF OF

KENTUCKY UTILITIES COMPANY

AND LOUISVILLE GAS & ELECTRIC COMPANY

Filed: April 10, 2017

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PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. ARE YOU THE SAME JOHN J. SPANOS WHO PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. In my rebuttal testimony, I respond to the recommendations of Kentucky Office of the Attorney General ("AG") witness Paul Alvarez, Kentucky League of Cities ("KLC") and Louisville/Jefferson Metro Government ("Louisville Metro") witness Jeffry Pollock, and Kentucky Industrial Utility Customers ("KIUC") witness Lane Kollen as they pertain to depreciation. Specifically, I will address Louisville Metro and KLC's inequitable recommendation to subsidize current customers with a significant reduction to depreciation based on a theoretical reserve imbalance, KIUC's recommendations to defer the recovery of net salvage costs for the Company's production plants until after they are retired and to use longer life spans for the Company's combined cycle and simple cycle gas-fired power plants, and the AG and KIUC's recommendations with regard to the recovery of legacy electric meters retired for the Advanced Metering System ("AMS") program.

II. INTERGENERATIONAL EQUITY

Q. What is depreciation?

A. Depreciation is defined in the FERC Uniform System of Accounts ("USofA"):

> 12. Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[1]

Q. What is the objective of depreciation?

A. The objective of depreciation is to allocate, in a systematic and rational manner, the full cost of an asset (original cost less net salvage) over its service life. The USofA requires this in General Instruction 22-A:

> Method. Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value[2] of depreciable property over the service life of the property.

Thus, the USofA confirms that depreciation represents the allocation of the full costs of a company's assets (original cost less any net salvage) over their service lives – that is, over the period of time the assets are providing service. Costs are allocated over the service lives of the assets so that customers pay for the costs of the assets that provide them service. Current customers should not pay for the costs of assets that have already

[1] 18 C.F.R. 101 (FERC Uniform System of Accounts), Definition 12.
[2] The USofA defines service value as the original cost less net salvage

been retired. Similarly future customers should not have to pay for the costs of assets that are no longer in service because current customers pay too little for their service.

Q. Have Mr. Kollen or Mr. Pollock conducted a depreciation study in this proceeding?

A. No. My depreciation study is the only one presented in this proceeding, so their recommendations are not consistent with the concepts of depreciation.

Q. Please explain the concept of "intergenerational equity."

A. Intergenerational equity is a ratemaking principle in which customers receiving the benefit from the use of an asset (e.g., from electric utility property used to provide electric service) are the same customers who pay the cost of that asset – no more, no less. There are actually two related concepts when considering intergenerational equity as it pertains to depreciation. The first is the inequity that results from a situation in which customers pay for assets from which they receive no service. For example, if a power plant is retired before becoming fully depreciated, then customers subsequent to the retirement will have to pay for an asset from which they are not receiving service. This type of inequity also occurs if a plant is retired before its terminal net salvage costs are recovered (which is what Mr. Kollen has proposed for the Companies' power plants). If the costs (including net salvage) of an asset are not recovered before the asset is retired, this is inequitable because one generation of customers will bear the cost of an asset from which they receive no service, but that instead provided service to an earlier generation.

The second concept is related to the distribution of depreciation over the entire life of an asset. For example, if depreciation expense is higher in the earlier years of an assets life and lower in later years (or vice versa), this could also be considered inequitable because one generation of customers pay a higher share than a different generation.[3] This second type of intergenerational inequity is exactly what Mr. Pollock proposes, as he recommends significantly lower levels of depreciation expense for the next five years.[4]

That is, there is a greater degree of inequity that results from a customer paying for an asset that only provided service to other generations of customers – and not to him or her – than results from one generation paying somewhat more or less than a previous generation for the same asset. Additionally, I would add that depreciation is necessarily a forecast of future events (such as the actual retirement date of a power plant) that will occur many years in the future. It is therefore very difficult to perfectly allocate costs equally over the lives of a utility company's entire asset base. This is one reason that the remaining life technique is the preferred approach for determining depreciation, as it allows for systematic and rational revisions to depreciation rates as more information becomes available for each successive depreciation study.

Q. Why is it important to explain the concept of intergenerational equity in your rebuttal testimony?

A. The concept is important to understand as it relates to both Mr. Pollock's and Mr. Kollen's testimony. Mr. Pollock discusses the concept in his own testimony and bases his proposal to amortize the theoretical reserve imbalance on this concept. However, as I explain in Section V of my rebuttal testimony, not only is Mr. Pollock's understanding of this concept as it relates to the theoretical reserve fundamentally incorrect, but his

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[3] I note here that one assumption inherent to this concept of equity is that the consumption of an asset is relatively equal over its useful life. However, this is not necessarily the case. For example, capacity factors of power plants typically tend to decrease over time, and thus the benefit to customers is often greater in the early years of the assets life than in the later years.

[4] I should note that Mr. Pollock's proposal also increases the probability that that the first type of intergenerational inequity would occur. His proposal increases the level of unrecovered costs for the Company's assets, and therefore increases the risk of stranded costs.

proposal will in fact create significant intergenerational inequity by creating a significant subsidy for current ratepayers.

Mr. Kollen does not discuss the concept of intergenerational inequity and instead appears to dismiss such considerations as "nonsense."[5] It should therefore be clear that Mr. Kollen gives little consideration to the concept of intergenerational equity, despite it being one of the primary objectives of depreciation.

III. TERMINAL NET SALVAGE

Q. What is terminal net salvage?

A. In order to understand the concept of terminal net salvage, I first need to explain the "life span method." Certain types of depreciable property are referred to as "life span" property, which means that a large percentage of the property at a facility is expected to be retired concurrently. Power plants are textbook examples of life span property. While many of the components of a plant (i.e. pumps, motors, turbine blades) will be replaced throughout the plant's life, upon the retirement of the entire plant all remaining assets will be retired concurrently. The retirements at the end of the life of the plant are referred to as "terminal" or "final" retirements, while the retirements that occur before this final retirement are referred to as "interim" retirements. Similarly, net salvage that occurs at the end of the life of the plant is "terminal" or "final" net salvage and salvage that occurs with interim retirements is "interim" net salvage. For power plants, terminal net salvage which is net of scrap value, is normally related to the costs of decommissioning and dismantling the power plant. There are also costs to retire the facility even if the entire

[5] Direct Testimony of Lane Kollen, p. 36, lines 11-15.

site is not decommissioned and remediated.

Q. Do both interim and terminal net salvage need to be recovered over the life of a power plant?

A. Yes, they do. Consistent with the USofA and authoritative depreciation texts, such as "Depreciation Systems and Public Utility Depreciation Practices", the service value of a power plant (or any asset) must be recovered equitably over its service life. The authoritative texts can be obtained on various locations such as Amazon.com or most libraries. The service value is the original cost less net salvage, and incorporates both interim and final net salvage. Recovering net salvage costs after a plant is retired, which appears to be Mr. Kollen's preferred approach, would, by definition, result in intergenerational inequity and cause future generations of customers to pay the costs of plants from which they receive no service.

Q. Mr. Kollen argues that terminal net salvage costs should be recovered through an "Asset Retirement Rider." Is Mr. Kollen's preferred approach equitable?

A. No. Mr. Kollen argues that the best approach for terminal net salvage is to recover these costs after a plant is retired through an "asset retirement rider." This approach will, by definition, produce intergenerational inequity, because future customers would have to pay for the costs of the Company's power plants after they are no longer providing service. Mr. Kollen recognizes that under his approach costs are recovered "only after they are incurred."[6] He therefore proposes a recovery pattern that is inequitable. In fact, he appears to dismiss the entire concept of intergenerational equity – that is, one of the primary goals of depreciation – as he states that his approach "avoids all the nonsense of

[6] Direct Testimony of Lane Kollen, p. 36, lines 11-12.

attempting to forecast the costs of dismantlement and remediation many decades before those events occur, if indeed they actually occur."[7] This statement alone should make clear that Mr. Kollen is in no way concerned with the concept of intergenerational equity. Forecasting future terminal net salvage costs is not "nonsense," but is instead necessary and required to achieve intergenerational equity and develop depreciation rates that are consistent with the Uniform System of Accounts.

Q. Mr. Kollen states that "[h]istorically, the utilities subject to the Commission's jurisdiction have retired generating units in place after stabilizing the facilities and securing the sites" and that "[t]hey have not dismantled the facilities or remediated the sites."[8] Please address his discussion.

A. The costs to stabilize the facilities and secure the sites are not insignificant. These costs include disconnecting equipment, removing chemical equipment and unsafe assets. Such costs should be included in depreciation expense and recovered while the plants are in service. This alone demonstrates that Mr. Kollen's proposal of $0 terminal net salvage is incorrect. Further, in making this statement Mr. Kollen ignores that LG&E and KU have experienced terminal net salvage costs in the past (at a minimum related to the retirement, if not full decommissioning, of facilities) and that the Company has incurred to date and have planned costs related to its retired Canal Street and Paddy's Run plants. Finally, by focusing only on plants in Kentucky, Mr. Kollen ignores the many plants (see examples on page 9 of this testimony) across the country that have experienced terminal net salvage in recent years. These facilities provide further evidence that terminal net salvage must be included in depreciation to achieve intergenerational equity.

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[7] Direct Testimony of Lane Kollen, p. 36, lines 13-15.
[8] Direct Testimony of Lane Kollen, p. 35, lines 8-10.

Q. Please provide an example of another power plant that has been retired and experienced significant terminal net salvage costs?

A. The Venice Plant, operated until its closure by AmerenMO, provides an example with which I am familiar. I have toured the site of the Venice Plant subsequent to its decommissioning and dismantlement. This example is instructive not only because it provides an illustration of the terminal net salvage costs involved with power plants, but also because the site continues to be used for generation by its owner. This example therefore provides evidence that terminal net salvage should be expected even if a generating site can be reused for other purposes after the closure of the facility.

Q. What was the experience of AmerenMO with the Venice Plant?

A. The Venice Power Plant was a six unit coal-fired power plant (which was converted to burn oil and gas in the 1970s) sited on the east bank of the Mississippi River near St. Louis. The plant was owned and operated by AmerenMO. The total capacity of the plant was 474 MW. In 2002, the plant was retired. Decommissioning and dismantlement occurred in the years subsequent to the retirement and was completed in 2013. Total costs expended by AmerenMO to retire the Venice Plant were approximately $36.3 million, which was offset by about $12.1 million in gross salvage. Thus, the total terminal net salvage cost for Venice was approximately $24.2 million. This cost equates to approximately $51 per kW, and is thus higher than my estimate for steam production plant of $40 per kW for LG&E and KU.

Q. Can you provide examples from other jurisdictions of power plants that have been or are planned to be decommissioned?

A. Yes. There are many recent examples of plants that either have been or will be decommissioned and dismantled. Some examples include:

- Black Hills Power will decommission its Ben French, Osage and Neil Simpson I plants.
- Black Hills Colorado Electric has decommissioned its Canon City (W.N. Clark) plant and is in the process of decommissioning units 5 and 6 at its Pueblo plant.
- Duke Energy is in the process of decommissioning a number of sites in the Carolinas, and activities related to the retirements of these sites include asbestos removal, demolition and the closure of ash ponds.
- Dominion Virginia Power is in the process of decommissioning coal units at its Chesapeake Energy Center, North Branch and Yorktown sites.
- PacifiCorp is in the process of decommissioning its Carbon coal power plant.
- Florida Power and Light has decommissioned a number of retired oil and gas fired steam power plants, including Cape Canaveral, Riviera, Cutler and Pt. Everglades.

Q. What is the basis for your estimates of terminal net salvage?

A. I based the terminal net salvage estimates on typical estimates for each type of facility used by others in the industry. For each type of production plant the estimates are made on a dollar per kilowatt basis. By using a value per kilowatt, larger plants will have a larger decommissioning cost estimate and smaller plants will have a smaller decommissioning cost estimate.

Q. What are the estimates per kilowatt for each type of plant?

A. For steam production plants, the estimate is that decommissioning will cost $40 per kW. For hydro production plant, the estimate is $10 per kW. For other production plant, the estimate is $20 per kW for the Cane Run combined cycle plant and $10 per kW for the other plants in this function.

Q. Can you further explain in detail how you determined that these $/kW amounts are reasonable?

A. First, I must state the $ per kW estimates were determined based on experience of other engineering firms that specialize in decommissioning studies. Although these studies are proprietary to the individual company, the levels of decommissioning were comparable to what is utilized for KU and LG&E. Also, as I have explained in discovery, the initial calculations of terminal net salvage was presented at an American Gas Association / Edison Electric Institute conference in 1993. That presentation also supports the $ per kW levels utilized by KU and LG&E, as do more current studies of Sargent & Lundy, Burns & McDonnell and Black and Veatch. My levels of $ per kilowatt is based on 30 to 40 studies by these firms and others.

Q. Can you provide examples of other cases in similar estimates to your estimates were used for terminal net salvage?

A. Yes. One such case is for Rocky Mountain Power Company in Utah (Utah Docket No. 13-035-02). In that case the Company did not have a decommissioning study performed and proposed $40 per kW for steam and $20 for other production. The support in that case was similar to what has been provided in the current KU and LG&E case. The estimates that are currently used by Rocky Mountain Power (they were approved through a stipulation) are similar[9].

It is notable that while some parties in the Utah case challenged the per kW estimates, they did not propose $0 terminal net salvage, as Mr. Kollen does in the instant case. For example, the Office of Consumer Services in the Rocky Mountain Power case recommended $30 per kW for steam, $8 per kW for other production excluding wind and $5 per kW for wind production. Thus, these estimates in the Rocky Mountain Power

[9] Steam facilities are $40/kW and other production are $15/kW.

case were higher than Mr. Kollen's $0 estimate in the instant case. This should provide further evidence that the $0 terminal net salvage estimate proposed by Mr. Kollen is unreasonable.

Another example is a case for Nevada Power Company (Docket No. 11-06007). Nevada Power owns both coal fired generation and gas other production (primarily combined cycle plants). Thus, many of its plants are comparable. I have presented the approved decommission estimates in a $/kW basis for each of Nevada Power's plants in Table 1 below. These estimates were based on site specific decommissioning studies and are the approved estimates from a fully litigated proceeding. The estimates shown in Table 1 for coal plants range from $41/kW to $92/kW, and are higher than the Company's estimate in this proceeding. They are obviously much higher than Mr. Kollen's estimate of $0. The Sunrise plant, which is not a coal unit, has an estimate of $34/kW, which is also higher than Mr. Kollen's estimate of $0. For the combined cycle plants, the estimates range from $9/kW to $21/kW (and to $69 $/kW if the older Clark plant is included). Thus, the Nevada Power estimates provide support that the estimates I have made for LG&E and KU are consistent with those from more detailed decommissioning studies as approved by a commission.

Table 1: Approved Decommissioning Estimates for Nevada Power Company

Plant	**Cost/kW**
Steam Production Plants	
Clark – Combined Cycle	69
Reid Gardner 1-3 - Coal	90
Reid Gardner 4 – Coal	92
Sunrise 1 – Gas	34
Navajo - Coal	41
Combined Cycle Plants	

Clark 5-8	69
Harry Allen 5, 6, 7	18
Higgins	21
Lenzie	12
Silverhawk	9
Other Plants	
Clark 4	5
Clark 11 to 22	7
Goodsprings	107
Harry Allen 3, 4	14
Sunrise 2	34

Q. Are you familiar in any cases in which Mr. Kollen has recommended a terminal net salvage or decommissioning estimate greater than the $0 he supports in the instant case?

A. Yes. Mr. Kollen was involved in a recent case in Florida for Florida Power and Light Company ("FPL"). In that case, FPL included an accrual for terminal net salvage (referred to as "dismantlement" in the FPL case). Mr. Kollen opposed certain parts of FPL's terminal net salvage estimates specifically related to contingencies in the estimates of terminal net salvage, but his recommended expense levels included terminal net salvage.[10] As a result, terminal net salvage was adopted and continues to be accrued.

Q. What do you conclude regarding terminal net salvage?

A. Depreciation principles as set forth in the USofA and by the Commission require that net salvage is included in depreciation expense and allocated over the period that the related plant is providing service. The exclusion of net salvage costs results in intergenerational inequity because future customers will be required to pay for the costs of retired assets that are no longer providing service. Mr. Kollen's recommendation does not meet the

[10] See p. 34, lines 16-20 of the Direct Testimony of Lane Kollen in Docket No. 160021-EI before the Florida Public Service Commission.

requirements of the USofA and will produce intergenerational inequity. His recommendation is also inconsistent with his recommendation in at least one other jurisdiction. For the reasons set forth in my testimony, the Commission should reject Mr. Kollen's proposal and accept the depreciation rates proposed in my depreciation study.

IV. LIFE SPANS FOR SIMPLE CYCLE AND COMBINED CYCLE POWER PLANTS

Q. How are depreciable lives estimated for life span property?

A. In the previous section I explained the concept of life span property. The life span method is used for the Companies' power plants. In order to properly determine depreciation rates and expense for life span property, one must make estimates of both final retirements and interim retirements. Final retirements are typically estimated for each production plant or generating unit by determining the most likely date at which the facility will retire. This date is referred to as the "final retirement date" or "probable retirement date." A related concept is the "life span" of the facility, which is the period of time from the original installation of the facility to the final retirement date of the facility. Thus, if a power plant is constructed in 1990 and retires in 2030, it will have a 40-year life span.

It should be noted that the life span of a facility is different from the average service life of the facility. The average service life of the facility is shorter than the life span, for two reasons. One is that any additions that occur subsequent to the original installation of the facility will have a shorter life than the original additions. For example, for a facility with a final retirement date of 2030, assets installed in 2010 will have a shorter life than those installed in 1990. The second reason is there will typically be interim retirements that occur throughout the life of the facility. These interim retirements are most commonly and most accurately estimated using survivor curves, similar to the approach for mass property.

Once estimates of both final retirement dates and interim retirements are determined (as well as net salvage for each type of retirements), these estimates are combined to develop overall depreciation rates.

Q. Have any parties challenged the service lives for KU's and LG&E's production plant facilities?

A. No party has challenged the interim survivor curve estimates in my study, and no party has challenged the life spans for the Companies' Steam and Hydro facilities. Witness Kollen has recommended longer life spans for some of the Companies' simple cycle and combined cycle power plants.

Q. How are life spans determined for life span property?

A. The estimated life span or retirement dates are determined based on specific considerations for each facility. Considerations may include the type of facility, the usage of the facility, Company plans and life spans for similar facilities. Forecasting the life span of a power plant is inherently difficult, as the decision to retire a plant may occur many years in the future. The retirement of a power plant is most often the result of an economic decision. As a plant ages and becomes more expensive to operate, and as new technologies become more efficient and economical relative to existing generation, it eventually becomes economical to replace the existing plant. The retired plant may be able to physically operate for a longer period of time, but it would be the more costly option to keep the plant in service.

Thus, the process of estimating the life spans of the Companies' power plants is not to determine how long a plant could physically last, but instead estimating when the economic decision will occur to replace the plant with newer generation.

Q. You indicated that one consideration is a comparison to life spans for similar facilities. Do you have any comments on such comparisons?

A. Yes. When comparing life spans of other facilities, care must be taken to ensure that the comparable plants are in fact similar to the facilities being studied. Plants that have different technologies, operating environments, or operating characteristics can have very different lives. For example, it makes little sense to compare the life span of a small black start peaker facility that rarely operates to a base load combined cycle plant.

Q. What are the current life spans for the Companies' combined cycle and simple cycle gas plants?

A. The current life spans approved by the Commission are the same life spans I have proposed in the Depreciation Study.

Q. What has Mr. Kollen proposed for the life spans of combined cycle ("CC") and simple cycle combustion turbine ("CT") power plants?

A. Mr. Kollen has recommended "a life span of at least 45 years for all CT and CC generating units."[11]

Q. What is the basis for Mr. Kollen's proposal?

A. Mr. Kollen bases his recommended life spans on life spans experienced or projected for some of the Companies' older peaker CTs. This is not a sound basis for establishing life spans, as the technologies of the older CTs are dramatically different from newer units

[11] Direct Testimony of Lane Kollen, p. 39, lines 1-2.

such as the Cane Run combined cycle plant. The older CTs are smaller peaker facilities that run infrequently and require little capital investment to continue to operate in their limited capacity. For these reasons, these plants may remain in service for a longer period of time. In contrast, the Cane Run CC plant is a modern baseload combined cycle plant that operates continuously and requires significant capital additions and maintenance to continue to operate. These different technologies and operating characteristics are in no way comparable to those of the older CT units. It is not appropriate for Mr. Kollen to base the life span estimates for a combined cycle facility (or newer CTs) on the experience for older, completely different power plants.

Q. Please explain further why the life spans for the Companies' newer CC and CT power plants should not be based on the life spans of the Companies' older facilities.

A. As discussed above, the retirement of a power plant is an economic decision based on whether newer technologies are more economical than the existing technologies at the time the decision is made to retire a power plant. Often this type of decision occurs when major capital investments are needed to extend the life span of a power plant beyond its original design life. For example, a combined cycle plant may require investments to replace rotors in the combustion turbine or may require major investments to the heat recovery steam generator ("HRSG"). Similarly, modern CTs may require major investments in replacements of rotors or step up transformers that result in decisions about the economics of continuing to operate the facility. If newer technology is more economical at the time these investment decisions are made, then the existing power plant will be retired and replaced with a newer, more cost effective power plant. For this reason, even though the Company may have had some older, different types of power plants last longer than the life spans estimated for newer CTs and CCs, it would be inappropriate to simply assume that this means that all plants will have longer life spans. Yet this is exactly the assumption that Mr. Kollen makes. He has compounded this error in judgment by improperly comparing plants with different technologies and operating characteristics.

Q. Are you familiar with any authoritative depreciation texts that support your discussion of how life spans are determined?

A. Yes. *Depreciation Systems* by Frank Wolf and Chester Fitch ("Wolf and Fitch") is a well-regarded depreciation text. Wolf and Fitch discuss this very concept in a section entitled "Forecasting Life Spans":

> The other general force of retirement is a combination of factors that render continued use of the facility uneconomical. The terms *defender* and *challenger* are useful here. Defender refers to the facility currently in service. With each passing year, the incremental costs of keeping the facility in service for one more year tend to increase. Maintenance and operational costs tend to increase with age. Compliance with governmental regulations relating to safety or protection of the environment may require modifications that increase the annual cost of the defender. Each year the service provided by the defender may become less adequate, resulting in additional direct costs of providing additional service or intangible costs resulting from customer dissatisfaction.
>
> The challenger is a new facility that can be purchased or constructed to replace the defender. The challenger represents the most efficient design, the newest technology, and provides for current operational needs. Although acquisition of the challenger requires a larger capital expense, it provides better service and lower annual maintenance and operational costs than the defender.

> As each year passes, design and technology improve and operational needs change, and the gap between the efficiencies of the defender and the challenger widens. Eventually, potential savings associated with the difference in annual costs between the defender and challenger offset the annualized initial cost of the challenger, so that it becomes more economical to construct a new facility than to continue to operate the current facility. An economic analysis that considers these factors will result in an estimate of the time when it is no longer economical to continue operation of the current facility. This will not be a specific year, but a period when the incremental cost of keeping the defender one more year is about equal to the annualized cost of a new facility. [12]

Q. While most combined cycle power plants are fairly new, are you familiar with any that have been retired?

A. Yes. FPL recently retired its Putnam Combined Cycle power plant. Consistent with the discussion above, Putnam was retired because newer, more efficient power plants were more economical than continuing to operate the Putnam facility. Putnam was both less efficient than newer combined cycles and had become more expensive to operate (and less frequently available to generate electricity) as it aged.

Q. How old was the Putnam plant when retired?

A. There were two combined cycle plants at Putnam. One was retired at 36 years of age and the other at 37 years of age. Thus, this experience supports that the 40 year life span I have recommended for Cane Run is more appropriate than the longer life span proposed by Mr. Kollen. I should note that while Putnam was an older power plant, its technology

[12] *Depreciation Systems*, Frank Wolf and Chester Fitch, 1994, pp. 258-259.

was much more similar to Cane Run than LG&E and KU's older peaker plants that Mr. Kollen uses as a basis for his proposals.

Q. Is Mr. Kollen familiar with the experience of the Putnam plant?

A. Yes. I believe him to be since he was a witness in FPL's most recent rate case. I should note that Mr. Kollen did not challenge FPL's 40 year life spans for combined cycle power plants (although he did challenge the life spans for some of FPL's coal-fired power plants), which are the same life spans I have used for Cane Run.

Q. What do you recommend for the Company's CC and CT power plants?

A. I recommend the life spans that are set forth in my depreciation study. These estimates are consistent with the current life spans for these facilities. Mr. Kollen has not provided a sound reason to modify these life spans, and instead has inappropriately compared life spans of power plants with different technologies and operating characteristics.

V. THEORETICAL RESERVE IMBALANCE

1. Introduction

Q. What are the recommendations in this case regarding the theoretical reserve imbalance?

A. The Company has recommended the remaining life technique, consistent with the depreciation methods, techniques and procedures the Commission has approved for KU, LG&E and for other Kentucky utilities. Mr. Pollock recommends that the estimated theoretical reserve imbalance be amortized over a five year period.[13] I address Mr. Pollock's proposals in the sections that follow. I first address a number of general

[13] Direct Testimony of Jeffry Pollock, p. 10.

depreciation and ratemaking issues relative to Mr. Pollock's proposed adjustment. I then discuss a number of specific claims made by Mr. Pollock regarding LG&E and KU's theoretical reserve imbalances.

Q. What is a theoretical reserve imbalance?

A. A theoretical reserve imbalance ("TRI" or "imbalance") is calculated as the difference between a company's book accumulated depreciation, or book reserve, and the calculated accrued depreciation, or theoretical reserve.

I should note that different terms have been used for the theoretical reserve imbalance, including "theoretical reserve variance," and "theoretical excess depreciation reserve." Mr. Pollock uses the term "reserve surplus" to indicate when a TRI is positive (i.e., the book reserve is greater than the theoretical reserve) and the term "reserve deficiency" to indicate when a TRI is negative. For this testimony I will use the term "theoretical reserve imbalance," which is consistent with the terminology used in NARUC's *Public Utility Depreciation Practices* text.

Q. What is the book reserve?

A. The book reserve, also referred to as the "book accumulated depreciation" or the "accumulated provision for depreciation," is a running total of historical depreciation activity. It is equal to the historical depreciation accruals, less retirements and cost of removal, plus historical gross salvage. The book reserve also represents a reduction to the original cost of plant when calculating rate base.

Q. What is the theoretical reserve?

A. The theoretical reserve is an estimate of the accumulated depreciation based on the current plant balances and depreciation parameters (service life and net salvage estimates) at a specific point in time. The theoretical reserve technically represents the portion of the depreciable cost which will not be allocated to expense through future whole life depreciation accruals, if current forecasts of service life characteristics and net salvage materialize and are used as a basis for depreciation accounting

Q. How is the theoretical reserve calculated?

A. Using the average service life procedure employed for this study, the theoretical reserve is calculated for each vintage in each depreciable group using the following formula:

$$\textit{Theoretical Reserve} = (\textit{Original Cost} - \textit{Net Salvage}) \times \left(1 - \frac{\textit{Remaining Life}}{\textit{Average Service Life}}\right)$$

The remaining life and average service life are determined for each vintage (year of installation) based on the survivor curve estimate (life and dispersion pattern). The theoretical reserve for an account is equal to the sum of the theoretical reserve amounts for each vintage.

Q. Why is it called theoretical?

A. The reserve is called theoretical because it is not based upon actual recorded depreciation resulting from the application of depreciation rates used by the Company and approved by the Commission. Instead, it is an estimate based on the formula described previously.

Q. Why does one calculate a theoretical reserve?

A. A theoretical reserve is calculated as an analytical tool or benchmark to identify how current estimates compare to the provisions using previous estimates in calculating annual depreciation. It can also be used as a basis to allocate the book reserve to accounts, subaccounts or vintages of plant. A theoretical reserve calculation provides a snapshot of the reserve, valid only at the time it is calculated, since any changes in the proposed parameters change the theoretical reserve.

Q. Mr. Pollock argues that the difference in the book and theoretical reserve represents a "surplus" in the accumulated provision for depreciation. Is this accurate?

A. No. While there is a difference between book accumulated depreciation and the theoretical depreciation reserve, this amount is not a "surplus." It is simply a theoretical calculation of the difference between the actual accumulated depreciation based on the Company's historical experience and Commission approved depreciation rates, and a theoretical amount based solely on the proposed depreciation parameters. Depreciation is a prospective calculation, and thus changes as life and net salvage parameters change in future studies. As the Company moves through time with varying experience, this difference can change positively or negatively.

Q. What is Mr. Pollock's specific proposal in this case?

A. Mr. Pollock is proposing to amortize the calculated theoretical depreciation reserve imbalance more rapidly than results from using the more widely accepted remaining life technique. The remaining life technique has been accepted by the Commission for utility companies in the past. To my knowledge, Mr. Pollock's approach has not been approved in Kentucky.

Mr. Pollock's proposal would significantly reduce depreciation expense for the next five years, but then result in higher depreciation expense subsequent to that period of time. His recommendation is, therefore, best considered as a subsidy to ratepayers who will receive service for the next five years, as this group of customers will pay significantly less for their service than any other generation of customers.

Q. Is Mr. Pollock's approach common practice in the industry?

A. No, it is anything but common. Most utilities, Commissions and depreciation texts agree that theoretical reserve differences will be and are best resolved using the remaining life method. I will discuss the acceptance of proposals similar to Mr. Pollock's in more detail in the next section.

<u>2. Treatment of Theoretical Reserve Imbalances</u>

Q. Mr. Pollock claims that the continued use of the remaining life technique is not the best method to address what he alleges to be the excess reserve situation. Do you agree?

A. No. I should first address Mr. Pollock's implication that his proposal for an accelerated recovery of the reserve imbalance is the default or preferred approach. Contrary to Mr. Pollock's testimony, the remaining life technique is the most widely accepted approach and should be used, unless unique and significant circumstances otherwise warrant deviation. No such circumstances exist for LG&E or KU, and there is therefore no reason to deviate from the remaining life technique. Instead, the theoretical reserve imbalance developed over many years. It has not developed in the recent past. It therefore should not be resolved in a short period of time, as Mr. Pollock proposes. It is more appropriate to allocate costs through depreciation over the remaining time the Company's assets will be in service using the remaining life technique. Mr. Pollock's approach is a short-term subsidy for today's customers, which will result in increased costs for future customers.

Q. Referring to authoritative sources, what does the National Association of Regulatory Utility Commissioners (NARUC) say regarding this issue?

A. NARUC makes a number of comments regarding theoretical reserve imbalances in its publication *Public Utility Depreciation* Practices. On page 189, NARUC states:

> When a depreciation reserve imbalance exists, one should investigate why past depreciation rates, average service lives, salvage, or cost of removal amounts differ from the current estimates. Care should be taken to analyze these effects before correcting for the reserve imbalances. Instances occur where subsequent experience shows the original estimates no longer to be appropriate. It should be noted that only after plant has lived its entire useful life will the true depreciation parameters become known.[14]

Q. Have you investigated what caused the theoretical reserve imbalance?

A. Yes. One reason is that changes in service life and net salvage estimates have occurred over time due to the normal depreciation study process. These have occurred over many decades and are not a recent occurrence. It is therefore most appropriate to use the remaining life technique, which in effect takes action to correct the reserve imbalances over the remaining period of time the assets will be in service. This is most consistent with the fact that the theoretical reserve imbalance developed over many years. It should be clear from the passage above that NARUC recommends caution before making any significant adjustments, such as those made with Mr. Pollock's proposal.

Additionally, much of the theoretical reserve imbalance is related to steam production plant. As I will discuss in more detail in Section V.4, the theoretical reserve imbalance for life span accounts such as steam production accounts is an imperfect measurement. Specifically, the Company has made very significant investments in recent years that have resulted in longer life spans for many steam production facilities. However, these investments mean that future customers will pay much more for these plants than customers did in the past. As a result, the theoretical reserve imbalance for steam production plant in no way represents intergenerational inequity. In fact, the existence of a theoretical reserve imbalance for these accounts is reasonable and arguably

[14] *Public Utility Depreciation Practices*, NARUC, 1996, pp. 189.

represents a more equitable recovery pattern than if there were no theoretical reserve imbalance for these accounts.

Further, the new additions to these plants will be recovered over their remaining lives. Because these major investments are what has allowed longer life spans to be attained, it therefore also makes sense for the theoretical reserve imbalances that result from longer life spans to be allocated over the remaining lives of the plants – not over a shorter period of time as Mr. Pollock proposes.

Q. Does NARUC provide additional guidance addressing the remaining life technique?

A. Yes. NARUC also notes that:

> The desirability of using the remaining life technique is that any necessary adjustments of depreciation reserves, because of changes to the estimates of life and net salvage, are accrued automatically over the remaining life of the property. Once commenced, adjustments to the depreciation reserve, outside of those inherent in the remaining life rate would require regulatory approval.[15]

Combined with the NARUC passages cited earlier that urge caution, my interpretation of NARUC's recommendation is that for companies like LG&E and KU that use the remaining life technique, any accelerated amortization such as proposed by Mr. Pollock must be based on very unique circumstances that justify specific Commission approval. Such circumstances do not exist for LG&E and KU.

Q. Has the Commission accepted the use of the remaining life technique for LG&E and KU?

A. Yes. The Companies have used the remaining life technique for developing depreciation rates for many years.

Q. Do you believe there are unique circumstances for LG&E or KU to justify such an

[15] NARUC, p. 65.

adjustment?

A. No. As I have explained, unique or significant circumstances have not caused the theoretical reserve imbalance that would require any approach other than the use of the remaining life technique. Further, not only has Mr. Pollock not identified any such circumstances, he has not even bothered to investigate the causes of the theoretical reserve imbalance. The estimated theoretical reserve imbalance has developed over a long time due to the normal process of estimating depreciation through periodic depreciation studies. There is nothing unique to this occurrence. The estimates today are simply different from those in the past due to the different information that is available upon which the depreciation estimates are based. Such a circumstance of changing estimates occurs with every utility, as the estimation of depreciation involves predicting events that will occur many decades into the future.

Q. Is the theoretical reserve imbalance smaller in the current case than in the last depreciation study?

A. Yes. The difference between the current reserve balance and theoretical reserve has declined in the four years since the 2011 Depreciation Study. In the 2011 Depreciation Study for KU, the theoretical reserve imbalance was approximately $449 million, or 23% of the theoretical reserve. This compares to the TRI in the current study of approximately $408 million, or 17% of the theoretical reserve. Thus, the theoretical reserve imbalance has declined in the past four years. For LG&E, the change has been even more significant. In the 2011 study, the TRI was approximately $251 million, or 16% of the theoretical reserve calculated in the 2011 study. The current TRI for LG&E is approximately $103 million, or 7% of the theoretical reserve imbalance calculated in the 2016 study. This demonstrates that a theoretical reserve imbalance can change significantly from one study to the next. Similar reductions occurred in the studies prior to 2011.

Q. Are you familiar with any cases in which a proposal by Mr. Pollock for an accelerated amortization of the theoretical reserve imbalance was rejected by a commission?

A. Yes. Mr. Pollock and I were both involved in a recent case for MidAmerican Energy in Iowa. Mr. Pollock represented Deere & Company ("Deere") in that case and made a proposal similar to his recommendation in the instant case to amortize a theoretical reserve imbalance over a short period of time. Mr. Pollock's proposal was rejected by the Iowa Utilities Board, which stated:

> Deere's proposed adjustment is based on a theoretical account balance that will change over time for many reasons and it will not be known until an asset is retired whether any theoretical surplus or deficiency is accurate. MidAmerican's method uses the remaining life of an asset, which results in the theoretical reserve for any individual asset being reduced to zero by the time it is retired.
>
> The Board is concerned that under Deere's proposal, current customers would receive a benefit at the expense of future ratepayers because of the significant increase in rates (about $90 million) that MidAmerican projects in year nine if Deere's proposal is adopted. This increase would subject future customers to an unwarranted increase for the benefit of today's customers. MidAmerican's remaining life method to deal with any theoretical reserves moderates the recovery pattern and does not contribute to volatility in rates.
>
> The Board will reject Deere's adjustment. MidAmerican's depreciation proposal does not require a theoretical reserve but uses the well-established remaining life method for depreciation, with the theoretical reserve calculated only to compare current events to previous estimates that were used to calculate depreciation. MidAmerican's remaining life method is consistent with GAAP accounting and has been used in prior depreciation studies.[16]

[16] Order in Iowa Docket No. RPU-2013-0004, p. 19.

Q. Do you agree that the cases cited by Mr. Pollock should be precedent setting in Kentucky?

A. Absolutely not. Again, these are isolated cases. Further, for at least two of the companies cited by Mr. Pollock the approach of amortizing the theoretical reserve imbalance over a shorter period of time was not accepted by FERC. The Progress Energy Florida case was also set before the Federal Energy Regulatory Commission (FERC) in Docket No. ER11-2584-000. FERC stated in its Order:

> In this regard we note that this Commission has addressed any alleged excess or deficiency in depreciation reserves through adjustment of depreciation rates that eliminate such excess or deficiency over the remaining life of a utility's plant, rather than any shorter period.[17]

In other words, an accelerated amortization of the reserve was not accepted. Additionally, FERC further stated in Docket No. ER11-3584-000 that:

> In Order No. 618 and in the February 28 Order, the Commission stated that the cost of property used in utility operations should be allocated in a "systematic and rational manner" to periods during which the property is used in utility operations, i.e., over the property's remaining estimated useful service life. For this reason, changes in asset depreciation estimates, including cost of removal, should be made prospectively over the asset's remaining life. Florida Power proposes to adjust its depreciation reserves by $65,840,613 in 2010 and intends to adjust its depreciation reserves by varying amounts in 2011 through 2013 rather than allocating the excess depreciation reserves over the remaining service lives of the related utility plant. While these adjustments may be acceptable for retail ratemaking purposes, they do not conform to our requirements for allocating the costs of utility plant over their service lives. Accordingly, we will direct Florida Power to reinstate all such adjustments to its depreciation reserves (Account 108). Florida Power must also re-file its 2010 FERC Form No. 1 to reflect the restatement of its depreciation reserves.[18]

Q. Based on FERC's decision cited above, does FERC consider Mr. Pollock's proposal

[17] Order in FERC Docket No. ER11-2584-000, p. 10, footnote 44.
[18] Order in FERC Docket No. ER11-3584-000, paragraph 9.

consistent with the Uniform System of Accounts?

A. No. I interpret the discussion cited above to mean that the Uniform System of Accounts requires that any reserve imbalances be allocated over the remaining lives of a Company's assets (e.g., by using the remaining life technique). Mr. Pollock's proposal would not allocate the Company's costs over the service lives of its assets in a systematic and rational manner, and therefore would not be consistent with the Uniform System of Accounts.

3. The Theoretical Reserve and Intergenerational Equity

Q. Please summarize this section of your testimony.

A. In this section I address claims by Mr. Pollock that the theoretical reserve imbalance represents "intergenerational inequity" and current customers are subsidizing costs for future customers.

Q. Do you agree that the theoretical reserve imbalance represents intergenerational inequity?

A. No, the existence of a theoretical excess reserve imbalance does not represent intergeneration inequity, nor does it indicate that customers have overpaid depreciation expense. As I explain below, this claim is not consistent with authoritative depreciation texts.

Q. Mr. Pollock states that the theoretical reserve imbalance means that "the current generation of customers is subsidizing future customers."[19] Is Mr. Pollock correct?

A. No. Mr. Pollock's statement fundamentally misunderstands the Company's theoretical

[19] Direct Testimony of Jeffry Pollock, p. 9, lines 3-4.

reserve imbalance. First, the theoretical reserve imbalance developed over the entire history of the Company. It is not the result of what current customers have paid, but also many previous generations of customers. Further, as noted previously, the theoretical reserve imbalance existed in previous studies, and was in fact larger in the 2011 study. Thus, current customers have not "overpaid", and have in fact paid less than the theoretical whole life depreciation accruals since at least the 2006 depreciation study.[20] Mr. Pollock's understanding as to which generation of customers have contributed to the theoretical reserve imbalance is therefore incorrect. Further, as I explain in more detail in Section V.4, significant investments in the Company's steam production facilities mean that future customers will pay much more for the same power plants than previous generations have paid. These investments, which have resulted in the current longer life spans for these facilities, will be recovered over the remaining lives of the facilities. It is therefore equitable to also allocate any resulting theoretical reserve imbalances over their remaining lives.

Q. Has Mr. Pollock provided any specific evidence to demonstrate that the theoretical reserve imbalance means that such overpayments have occurred and that this represents intergenerational inequity?

A. No. Instead, a reading of his testimony gives the impression that he regards a theoretical reserve imbalance as resulting in "intergenerational inequity" simply because the theoretical reserve imbalance exists.

Q. Does the existence of the theoretical reserve imbalance mean that there must be intergenerational inequity?

[20] This is because the theoretical reserve imbalances in prior studies have resulted in lower remaining life depreciation accruals than theoretical whole life accruals.

A. No. The theoretical reserve imbalance and the theoretical reserve are the result of a calculation that incorporates a number of assumptions, and that the theoretical reserve itself is a simple model of the very complex history of transactions that have resulted in current accumulated depreciation balances. For this reason, the theoretical reserve almost never matches the book reserve. The mere existence of a theoretical reserve is not evidence of intergenerational inequity, but is instead a function of the difficulty of modeling real world utility property and forecasting service life and net salvage. The theoretical reserve should not be confused with the "correct" book reserve.

Q. If the theoretical reserve is not a perfect measurement of accumulated depreciation, why is it calculated?

A. The calculation of a theoretical reserve is actually not required, nor is it necessary, when using the remaining life technique (as is the case for LG&E and KU), and is not used in the remaining life formula. Some analysts do not even calculate the theoretical reserve when performing depreciation studies that are based on the remaining life technique.[21] While the theoretical reserve can serve as a rough benchmark as to how current estimates compare to depreciation estimates and plant and reserve activity in the past, it should not be considered the "correct" reserve. Authoritative depreciation texts are clear that the status of the book reserve as compared to the theoretical reserve is not a prescription for any adjustments to the reserve.

Q. What does Mr. Pollock assume in his claims of "intergenerational inequity" for present customers?

[21] Gannett Fleming's calculations use the theoretical reserve for each vintage of plant to allocate the book reserve to each vintage. However, the theoretical reserve is not used as a basis for any other remaining life calculations. Other depreciation software does not allocate the book reserve to the vintage, and thus does not use the theoretical reserve for the calculations.

A. There are two important implicit assumptions inherent in his claims that I will discuss here. These assumptions are:

1. Estimates made today are completely accurate.
2. Previous depreciation rates for LG&E and KU, as accepted by the Commission, were "incorrect."

I will begin with the first assumption, as the problems with this assumption help to demonstrate some of the problems with the second.

Q. Is the assumption that estimates made today are completely accurate a valid assumption?

A. No. The estimation of depreciation is a very complex and difficult task, requiring the forecast of events (e.g. retirements and net salvage) to take place decades in the future. Because the future contains a great deal of uncertainty, the assumption that these estimates are completely accurate is not reasonable.

Q. Do any authoritative sources agree with this assessment?

A. Absolutely. Again, NARUC states that:

> Instances occur where subsequent experience shows the original estimates no longer to be appropriate. It should be noted that only after plant has lived its entire useful life will the true depreciation parameters become known.[22]

Thus, NARUC is quite clear that estimates should not be considered to be completely accurate.

Frank K. Wolf and W. Chester Fitch's *Depreciation Systems* (Wolf and Fitch) is another highly regarded, authoritative depreciation text. Wolf and Fitch also comment on the matter, stating:

> The CAD [theoretical reserve] is not a precise measurement. It is based on a model that only approximates the complex chain of events that occur

[22] NARUC, p. 189.

> in an actual property group and depends upon forecasts of future life and salvage. Thus, it serves as a guide to, not a prescription for, adjustments to the accumulated provision for depreciation.[23]

Given the complexities and uncertainties involved in estimating the future, we should not assume that the estimates in a depreciation study are completely accurate (which is an assumption inherent to Mr. Pollock's proposal). They are the best estimates given the best information available, but we will not know for sure that they are correct until the plant has lived its entire useful life.[24] In future studies shorter lives or more negative net salvage may be appropriate, at which point a large negative theoretical reserve imbalance (or reserve deficiency) would develop if Mr. Pollock's proposal were adopted. This would result in an even larger increase in rates (whether the remaining life technique or another reserve amortization were used). The remaining life technique provides for more stability in rates by allocating costs over the remaining lives, whereas Mr. Pollock's approach would lead to much more volatility.

Q. Please address the second assumption, that prior estimates were "incorrect."

A. First, an understanding that the accuracy of depreciation estimates is unknown until all plant has lived its full useful life demonstrates the fallacy of the assumption that the existence of a reserve imbalance means that prior estimates were wrong and previous customers are subsidizing costs for future customers. To make such an assumption inherently assumes that today we have perfect knowledge of the future. This is an unrealistic assumption. For example, as I discussed in Section IV and discuss in more detail in Section V.4, the estimation of a life span for a power plant involves determining

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[23] *Depreciation* Systems (1994), Frank K. Wolf and W. Chester Fitch, p. 86.

[24] To put this in context, the average service life estimates in the depreciation study for many accounts are in the 50 to 60-year range. These are only averages though, and the estimates mean that some plant will last longer than a 100 years. Thus, based on the service life estimates in the depreciation study, we will not know for certain if the estimates are correct for over a 100 years.

whether significant capital expenditures will be more economical than replacement generation many years in the future. Given that economic conditions and the economics of the operation of a fleet of generating facilities many years in the future is not something that can be known with certainty, it is unreasonable to expect estimates to be perfect and never be modified based on new information. Yet this is the implicit assumption in Mr. Pollock's recommendation to amortize the theoretical reserve imbalance over a short period of time.

Q. Are there additional issues with the assumption that prior estimates have been wrong?

A. Yes. As noted above, Wolf and Fitch explain that the theoretical reserve is a simple model of a "complex chain of events." Many of the simplifying assumptions[25] inherent to the theoretical reserve model are not necessarily reasonable assumptions regarding actual real-world experience.

Q. What assumptions are inherent to the theoretical reserve model?

A. One key assumption is that all vintages of plant have the same life characteristics. While the depreciable groups studied in a depreciation study (based largely on the FERC Uniform System of Accounts) are relatively homogeneous, there is variety within the accounts and not all assets, much less vintages of assets, will necessarily have the same life characteristics. For example, different materials may have been used for overhead conductors at different periods of time. If these different materials have different life characteristics, then the service life estimates will change naturally over time as the

[25] The assumptions discussed here are related primarily to assumptions regarding life characteristics. However, one assumption made regarding the way net salvage is normally calculated in the theoretical reserve is that average and future net salvage are equal. This is in fact often not the case, and future net salvage is typically greater than average net salvage. The effect of this assumption is therefore normally to understate the theoretical reserve and overstate an estimated theoretical reserve "excess."

composition of types of assets in the overhead conductors changes over time. For this reason, service life estimates today may be longer than would have been appropriate ten or twenty years ago. Because the service life estimate for the account is estimated for assets in service today, this natural change would result in a theoretical reserve imbalance due to the changing life characteristics over time. However, this does not necessarily mean that previous depreciation rates were too high, as Mr. Pollock implies. Instead, it simply means that the life characteristics for the account are dynamic and have changed over time.

In other words, given that different vintages of plant can have different life characteristics, it is incorrect to assume that the life estimates made today should have applied in the past for the entire history of the Company. Yet this is an assumption of the theoretical reserve model and an assumption Mr. Pollock makes in his recommendation for the theoretical reserve imbalance.

Q. What is another assumption inherent to the theoretical reserve model?

A. Another assumption is that life characteristics do not change over time. I have explained that different vintages of plant can have different life characteristics. However, the life characteristics themselves can change over time as well. For example, operational practices, maintenance practices and management decisions can change life characteristics over time. A good example is meters. An estimate that meters would last for 30 years was a reasonable estimate three or four decades ago. However, experience has shown that this was not a reasonable assumption ten years ago. The assets themselves did not change - the electromechanical meters 30 years ago were similar to those in service ten years ago - and the physical characteristics of these meters did not change. However, other considerations such as functionality or technology did change, which resulted in a significant change in life characteristics.

This example illustrates that life characteristics do change over time and the theoretical reserve is far too simplistic an assumption from which to draw the conclusion that previous depreciation rates resulted in an overpayment.

Q. Given these assumptions, do you agree that the theoretical reserve imbalance indicates that "intergenerational inequity" has occurred?

A. No. As discussed previously, the theoretical reserve calculation is too simple a model from which to draw such a conclusion.

Q. Do you have any other comments related to the claim that previous depreciation rates were too high?

A. Yes. The Companies' historical depreciation rates have been based on periodic depreciation studies in which the Companies have presented what it considers to be the best estimates of depreciation based on the information available at the time. Other parties have also had the opportunity to present their estimates based on the same information. Based on this process, this Commission has concluded that the depreciation rates used by the Companies were reasonable based on the information available at the time. That is, the book reserve for LG&E and KU is based on the depreciation rates that the Commission has historically recognized to be just and reasonable.

4. The Theoretical Reserve for Life Span Property

Q. Is a portion of the theoretical reserve imbalance related to life span property?

A. Yes. A large portion of the theoretical reserve imbalance is related to steam production plant. The power plants in this function of plant are life span property, which means that all of the assets at a facility (such as a power plant) will be retired concurrently upon the retirement of the facility.

Q. Are there any reasons why the theoretical reserve imbalance should be given less consideration for life span property?

A. Yes. As I have discussed in the previous section, the theoretical reserve imbalance is not a perfect measurement and should not be considered the "correct" reserve, as the approach set forth by Mr. Pollock would incorrectly imply. This is particularly the case for life span property, as the nature of facilities such as generating plants means that the theoretical reserve is a less meaningful benchmark for these types of property.

Q. Please explain.

A. As I explained in Section III, most of the assets at a power plant will be retired as terminal retirements. Therefore, the estimated retirement date has a significant impact on the depreciation accruals, book reserve and the theoretical reserve. Typically a plant will have an initial life span based on the original design of the plant (for example, 40 years for a coal-fired power plant). At some point in the plant's life it may be economical to make significant investments in the facility in order to extend this initial life span. However, whether it will in fact be economical to make these investments will not be known until many years into the plant's life. It would be inappropriate to simply assume when the plant is placed in service that these investments will be made and the life span will eventually be extended – doing so risks significant unrecovered costs and intergenerational inequity if it turns out the plant is actually retired at its initial design life. Instead, it is more appropriate to extend the life span of a facility when – and if – the decision is made to invest in extending the plant's life.

Extending the life span of a facility will typically result in the book reserve exceeding the theoretical reserve. Mr. Pollock would consider this a "surplus" and argue that future customers would "underpay" when compared to previous generations of customers. However, the opposite is true. Future customers typically pay much more for the facility than earlier generations of customers. This occurs because the depreciation rate for life span property tends to increase any time new assets are added to the plant.

Q. Why do capital additions for production plant result in an increase in depreciation rates?

A. Additions to life span property typically will result in an increase not only to depreciation expense due to a resulting higher plant balance, but also because additions typically increase the depreciation rate for this type of property. For life span property, interim additions (that is, additions added subsequent to the original in service date of the facility) will have a shorter service life than the original installation of the facility. This occurs because the facility has a final retirement date at which time all assets will be retired. Thus, for interim additions, the length of time between installation and the end of the life span of the facility is shorter than for the original installation of the plant.

To help illustrate this concept, consider as an example a power plant that is installed in 1980 for $1 million. For simplicity, assume that there will be no interim retirements and no net salvage. When the plant is installed, a life span of 40 years (and a retirement date of 2020) is estimated. The depreciation rate at the time of the original installation is 2.50%.[26] Assume that in 2010 an additional $1,000,000 is added to the facility, which allows the life span to be extended to 50 years (and a retirement date of 2030). These new assets will not have an average service life of 50 years, but instead

[26] Equal to 1/40

will have an average service life of 20 years since they will be retired in 2030. That is, the interim additions have a shorter service life than the original addition of the facility.

For this reason, all else equal, the overall average service life of life span property will decrease as new interim additions are made – and the overall average service life will also often decrease even if the life span is extended. In this example, the average service life after the $1,000,000 in 2010 is 35 years,[27] shorter than the estimated 40 year average service life when the plan was placed in service.

Similarly, the annual depreciation rate will tend to increase over time as interim additions occur. After the installation of the 2000 vintage assets the depreciation rate increases to 3.00%[28] from 2.50%. This occurs despite the fact that the life span estimate was increased, which results in a theoretical reserve imbalance. The reason the depreciation rate increases due to the interim additions to the facility.

This same concept explains increases in depreciation rates for LG&E and KU's production plant facilities, as significant additions have occurred at the Company's coal-fired power plants. All else equal, these additions cause increases in depreciation rates and are the primary factor contributing to the overall increase in depreciation expense resulting from the depreciation study

Q. Mr. Pollock states that "[i]t makes no sense to raise depreciation rates, especially for those accounts that have accumulated a large depreciation surplus."[29] Please address this claim.

A. Mr. Pollock's claim is incorrect, and simply demonstrates that he does not understand

[27] Equal to ($1,000,000 x 50 + $1,000,000 x 20)/($1,000,000 + $1,000,000).
[28] Determined on a remaining life basis by dividing the unrecovered cost by the remaining life of 20 years.
[29] Direct Testimony of Jeffry Pollock, p. 8, lines 7-8.

the factors influencing the Company's depreciation rate and that he has not investigated the Company's depreciation study or reserve imbalance in any detail. As I have discussed above, all else equal, capital additions to life span property increase depreciation rates. LG&E and KU have made very significant investments in pollution control equipment such as scrubbers and SCRs at many of their facilities. It is these additions that are the primary driver of the increase in depreciation rates. For example, for Ghent Unit 3 for KU the Company has added $70 million in 2004 and over $165.5 million in 2014. In addition, a scrubber was added in 2007 for a cost of more than $110 million. Of the total $544 million balance as of 2016 for Ghent 3 (including the scrubber), approximately $388 million – over 70% - has been added since 2004 and over half has been added since 2007. These additions have resulted in increased depreciation rates for this generating unit, and it therefore completely reasonable to expect an increase in depreciation rates for the current study.

It also makes sense that there would be a theoretical reserve imbalance for many of these plants. These types of additions have allowed the plants to operate for a longer period of time. Indeed, most of the facilities would have been retired within the past few years had the investments not been made. Thus, as I have discussed above, it is to be expected that there would be a theoretical reserve imbalance for steam facilities, as extending the life of the original installation tends to result in the theoretical reserve being less than the book reserve. However, the theoretical reserve imbalance for the Company's steam facilities is not an example of intergenerational inequity, but instead a result of the fact that life spans have been appropriately determined and had not been extended prematurely. That is, the life spans had correctly not been extended until it was known that it would be economical to make investments to extend the lives of these plants.

Q. Please provide an example using one of KU's power plants of how capital additions cause an increase in depreciation rates.

A. A good example to illustrate this concept is Ghent Unit 3. The current estimated retirement date is in 2037. However, this retirement date would not be attainable were it not for the significant additions mentioned above that occurred in 2004, 2007 and 2014. Figure 1 below illustrates the concept that capital additions to life span property increase the depreciation rate, all else equal. The figure shows the depreciation rates for Ghent Unit 3 based on a scenario in which depreciation studies conducted periodically using the same interim survivor curve and estimated retirement date of 2037 in each study.[30] That is, nothing changes each year except the plant and reserve balances.[31] However, as can be seen in Figure 1, the depreciation rate (and expense) increases significantly over time due to the capital additions to the facility.

[30] For simplicity, net salvage is not included in the calculations for this scenario. The overall impact would be similar if net salvage were included.
[31] This analysis is based on the actual additions to the Ghent Unit 3 depreciation group for the period 1981 through 2016. Future activity is based on projected annual additions and retirements through 2036 (although no additions are assumed in the last few years of the plant's life). Ghent Unit 3's scrubber is in a different depreciation group and is therefore not included in this analysis. However, the addition of the scrubber in 2007 had the result of increasing depreciation rates and expense further.

Figure 1

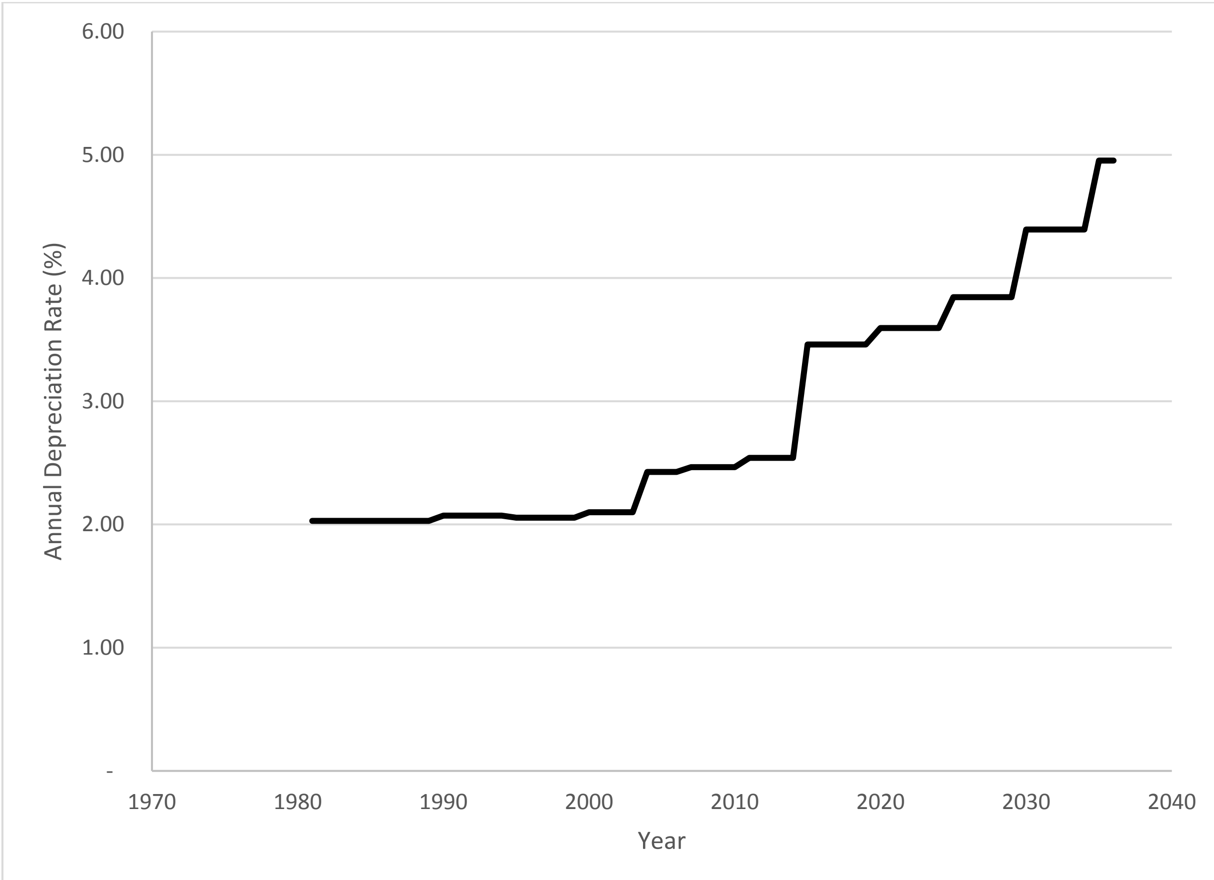
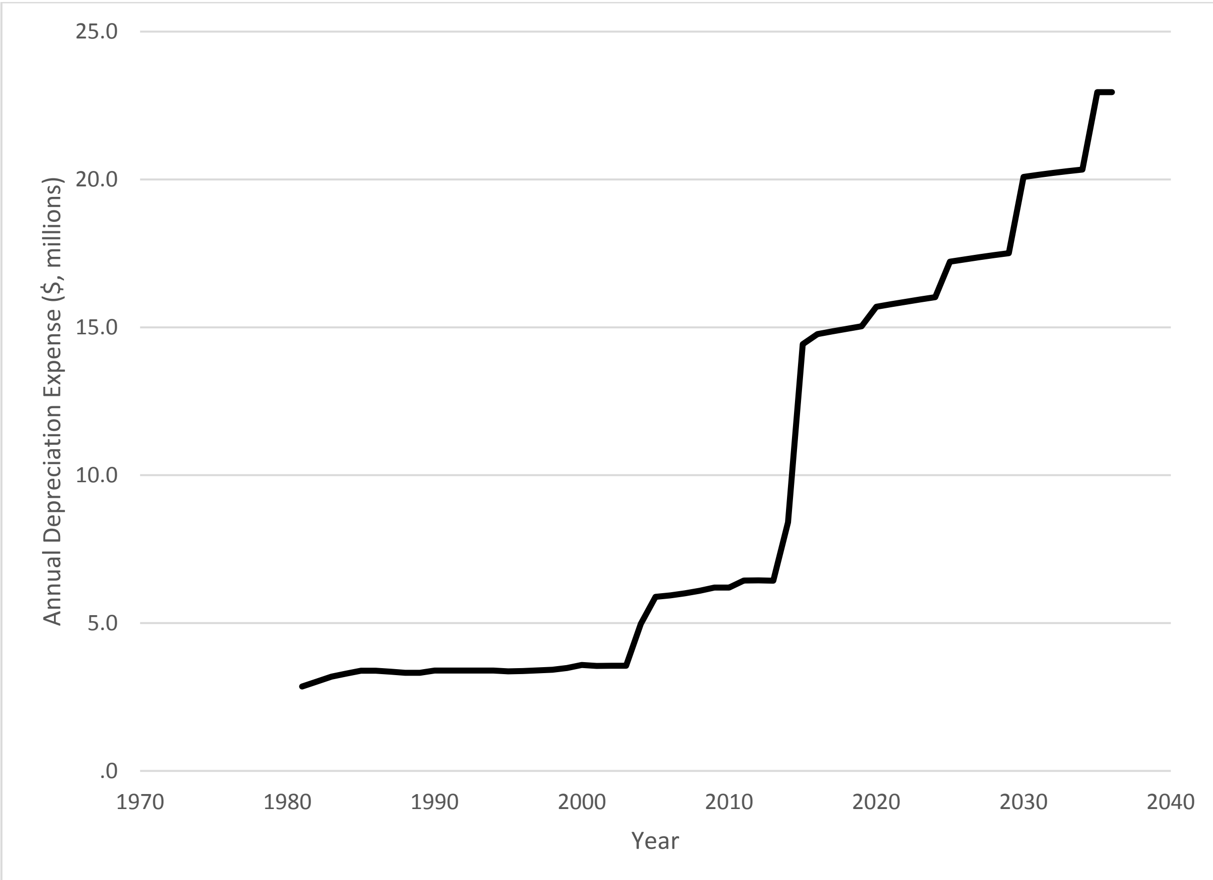


Figure 2 shows the depreciation expense amounts for each year for the same scenario. As can be seen in the chart, customers in later years pay much more than in the earlier years. For example, if the same life span is used throughout the plant's life, customers in the later years pay more than five times as much as customers in the early years of the plant's life. The increase in depreciation rates and expense that occurs in this scenario is due primarily to the additions to Ghent Unit 3.

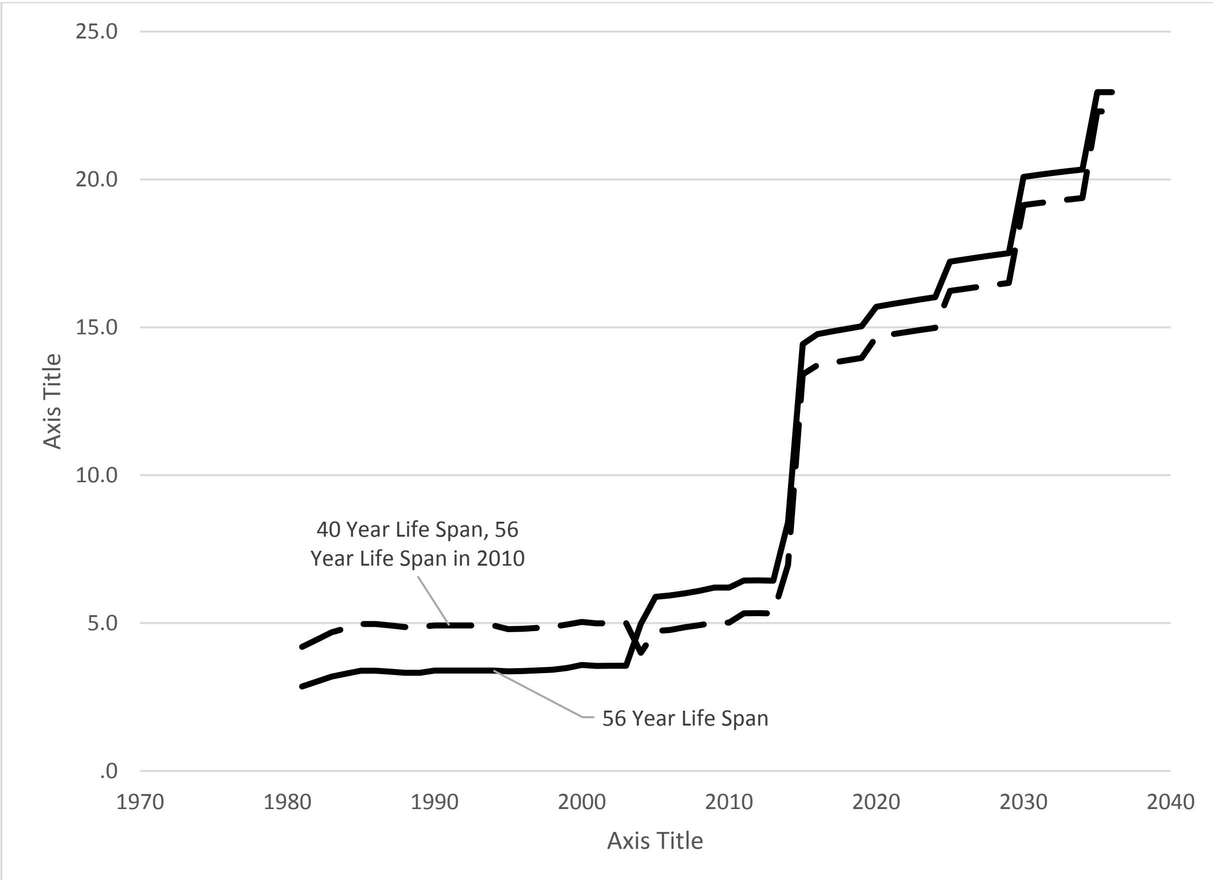
Figure 2



Q. How does the recovery pattern illustrated in Figures 1 and 2 compare to a scenario in which a shorter life span was used prior to these additions?

A. In Figure 3 below I have added a scenario in which a shorter life span was used through 2004 - the date of the first major addition to this generating unit. This scenario is more similar to what has actually occurred for KU. The solid black line in Figure 3 is the same as shown in Figure 2, and assumes the same 56 year life span (based on a retirement date of 2037) throughout the life of the facility. For the dashed line in Figure 3, a 40 year life span is used until the major additions are made in 2004. At this point, the life span is extended to the 56 year life span currently used for Ghent Unit 3.

Figure 3



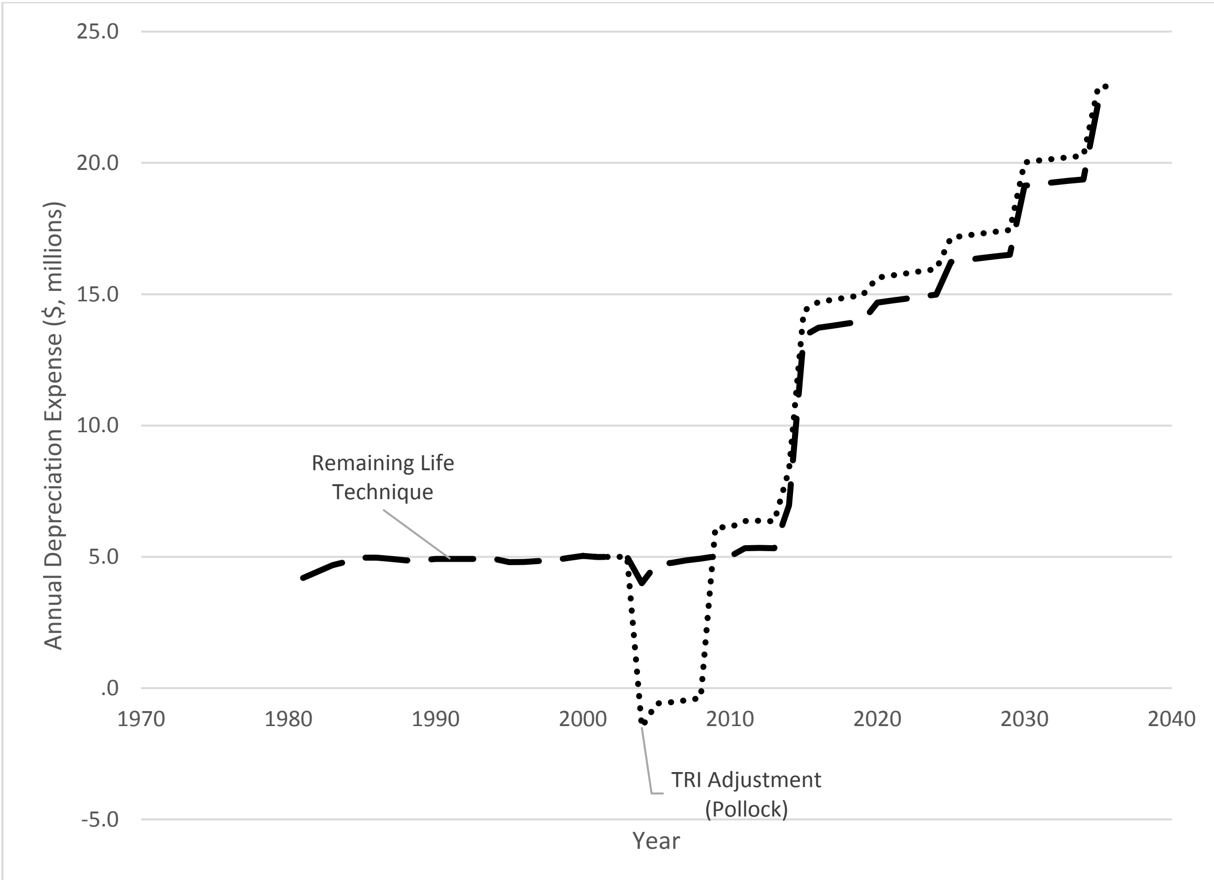
In this scenario, the change in life span causes a theoretical reserve imbalance of approximately $32 million to be calculated in 2004. However, as can be seen in Figure 3, it does not result in customers paying significantly less than customers who received service prior to 2004. Indeed, from 2005 through 2014 the annual depreciation accruals are similar to those prior to 2005. Further, while the large addition in 2014 significantly increases depreciation expense in both scenarios, the difference between the amount customers pay before and after 2014 pay is not as great in this scenario as is the case for the scenario in which the 2037 retirement date was used throughout the life of the plant. Thus, although the scenario shown in the dashed line results in a theoretical reserve imbalance, if anything it actually results in a more equitable recovery pattern than the a scenario in which a smaller TRI was developed (i.e., the scenario with a 56 year life span used in all years). That is, depreciation expense is arguably allocated in a more equitable manner over the entire life of the facility if a shorter life span is used initially – even though this results in a "theoretical" reserve imbalance when the life span is extended.

Q. Please also illustrate the impact of a TRI adjustment similar to the one proposed by Mr. Pollock.

A. Figure 4 below illustrates the impact of a proposal similar to Mr. Pollock's.[32] The dashed line labeled "Remaining Life Technique" is the same scenario as the dashed line in Figure 3 above. The dotted line labeled "TRI Adjustment (Pollock)" incorporates a proposal similar to that of Mr. Pollock. Specifically, when the life span is changed from 40 to 56 years after the additions in 2004 the resulting theoretical reserve imbalance is approximately $32 million. The dotted line shows the impact of amortizing this TRI over a five year period, similar to Mr. Pollock's proposal in the instant case.

[32] To illustrate the impact of a TRI adjustment such as made by Mr. Pollock, for this scenario I have made the TRI adjustment in 2004 when a TRI is first calculated. Presumably, Mr. Pollock would propose such an adjustment at that time. However, as discussed in more detail in the next section

Figure 4



Q. Does amortizing the theoretical reserve imbalance over a shorter period of time, as Mr. Pollock recommends, result in intergenerational equity in this example (as Mr. Pollock argues his recommendation does)?

A. No. In fact, the opposite is true. Mr. Pollock's preferred approach produces significant intergenerational inequity. Indeed, for the five years during which the amortization of the TRI is in place, the total depreciation expense is less than zero. That is, customers during that period of time do not pay anything for the service provided by Ghent Unit 3 (and in fact the Company is in effect paying customers to use the plant). This is clearly inequitable. Further, future customers (who will already have to pay a greater amount for the use of the plant due to the large additions that occur) will have to pay even more for their service, causing an inequitable burden for future customers.

Q. Does this example demonstrate that Mr. Pollock's recommendation is effectively a subsidy for customers who receive service during the period of the amortization?

A. Yes. It should be clear based on Figure 4 that customers receiving service during the period 2005 to 2009 in this example receive a significant subsidy and pay far less than the cost of their service. I will discuss this concept in more detail in the next section.

<u>5. Impact of Theoretical Reserve Imbalance Proposals</u>

Q. Please summarize this section of your testimony.

A. In this section I discuss further Mr. Pollock's claim of intergenerational inequity, and present a comparison of his proposal with the longstanding and widely accepted remaining life technique. Similar to the analysis presented in the previous section for Ghent Unit 3, the comparison I present in this section demonstrates that while Mr. Pollock presents arguments in support of his proposal regarding a perceived <u>theoretical</u> intergenerational inequity, his proposal will without a doubt <u>result</u> in intergenerational inequity.

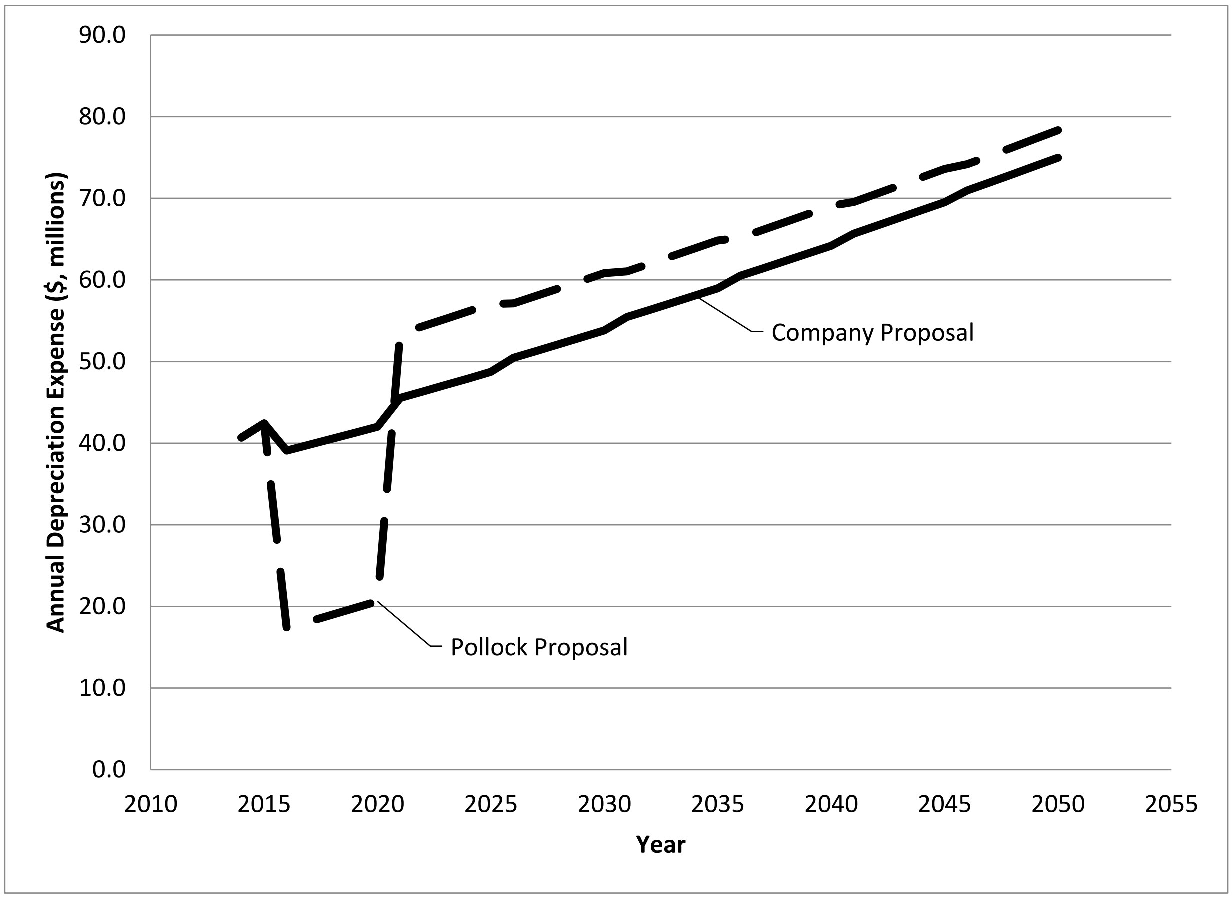
For KU's distribution plant accounts, I have modeled the impact of Mr. Pollock's proposal and the Company's proposal in Figure 5 below.[33] This sets forth what the resulting depreciation expense will be in each year going forward for distribution plant only. The Company's use of the remaining life technique is shown in the solid black line, and the proposal of Mr. Pollock for an accelerated amortization of the theoretical reserve imbalance is shown in the dashed black line.

As the figure demonstrates, the remaining life technique allocates costs evenly

[33] The overall results of this analysis would be similar for LG&E electric or gas distribution accounts.

over the remaining life of the assets.[34] That is, the remaining life technique represents the straight line recovery of unrecovered costs over the remaining life of the assets. Thus, going forward different generations of customers will pay a similar depreciation charge in each year. No generation of customers will be favored.

Figure 5



Q. How does this compare with the proposal of Mr. Pollock to accelerate the recovery of a portion of the theoretical reserve imbalance?

A. Figure 5 illustrates that customers who happen to be receiving service for the next five

[34] The lines for both recommendations increase over time due to the growth in plant balances. Straight line recovery therefore would result in a gradually increasing straight line, similar to the presentation for the Company proposal.

years will incur significantly lower depreciation expense than any other generation of customers. Indeed, these fortunate customers will pay less than half the expense paid future generations of customers. Any customer that enters KU's service territory after 2020 will pay significantly higher costs than customers that receive service in the next five years.

Q. Is this intergenerational inequity?

A. Yes. Figure 5 demonstrates that no matter the opinion of what has occurred in the past, Mr. Pollock's proposal to accelerate the amortization of the theoretical reserve imbalance will result in intergenerational inequity in the future. This is one reason that the remaining life technique is so widely used and accepted.

Q. Mr. Pollock presents an example in Exhibit JP-5 that he claims "illustrates how amortizing a depreciation surplus would restore intergenerational equity." Does his example of amortizing a theoretical reserve imbalance have similar problems to the example you present above?

A. Yes. In Mr. Pollock's example, which is presented in Exhibit JP-5, customers from Year 11 through Year 15 pay nothing in depreciation expense. This represents a significant windfall to any customer that happens to be receiving service during this time period. Customers from Year 11 to Year 15 effectively pay nothing for the return of the costs of the assets that provide them service. Thus, instead of "illustrating how intergenerational equity would be restored," Mr. Pollock's own example demonstrates the inequity of his proposal.

Q. Figure 5 presents the annual depreciation expense for distribution assets of each proposal. Will an accelerated amortization of the reserve imbalance impact any other aspect of customer rates?

A. Yes. Mr. Pollock's proposal will reduce the book reserve (as compared to the Company's proposal), resulting in increased rate base. A higher rate base means that the return paid by customers will therefore also be higher, resulting in a higher cost of service. The total cost to customers over the remaining life of the assets currently in service will also be higher under Pollock's proposal due to the rate base impact.

VI. AMS METERS

Q. What will you address in your testimony with regard to AMS Meters?

A. I will not discuss the prudence or economics of the AMS program. That will be discussed by Company witness John Malloy. Additionally, no party has challenged the recommended survivor curve of the 15-S2.5 in my depreciation study. I therefore do not need to address that recommendation further. However, I will address certain comments made by Mr. Kollen that are incorrect.

Q. Mr. Kollen states that your average service life recommendation for AMS meters means that you believe that "on average, all new AMS meters will be replaced once within a 15 year period." Is this correct?

A. No. Mr. Kollen's bases this statement on the 15-S2.5 survivor curve estimate I have made. While this estimate has a 15 year average service life, this does not mean that all meters will be replaced within a 15 year period. As I state in my direct testimony, the 15-S2.5 survivor curve has a maximum life of around 25 years. Thus, this estimate forecasts that it would take around 25 years for all meters to be replaced, not 15 years. The 15-S2.5 survivor curve forecasts that about half of the meters will be replaced within a 15 year period.

VII. CUSTOMER CARE SYSTEM SERVICE LIFE

Q. What is the current estimate for the Company's Customer Care System ("CCS") software?

A. The current service life estimate is for a 10 year service life. The depreciation rate I have recommended for these assets is 10.06%.

Q. What does Mr. Kollen propose for these assets?

A. Mr. Kollen proposes a depreciation rate of 3.52% for these assets. This depreciation rate would significantly under-recover the Company's major upgrade to this system that will occur in 2017. Based on a 10 year service life for these new assets, only approximately 35% (10 x 3.52%) of the costs of the major upgrade would be recovered by the end of its 10 year life in 2027. Thus, his recommendation is inadequate to recover the Company's costs in an equitable manner. I should note that this situation is in some ways similar to the discussion of the impact of additions on life span property in Section V.4, in that the new upgrades extend the life of the CCS assets. However, the new additions will also increase the depreciation rate similar to the impact of new additions to a power plant. Mr. Kollen's proposal, which only produces a 3.52% depreciation rate, does not take these new additions into account.

Q. How does Mr. Kollen develop his recommended 3.52% depreciation rate?

A. Mr. Kollen argues that a 2027 retirement date is appropriate for these assets, based on the plans to use the upgraded assets through 2027. However, while a 2027 retirement date may be appropriate for the new assets, Mr. Kollen calculates a 3.52% depreciation rate based only on allocating the unrecovered costs of the existing system (which is effectively obsolete as a standalone system since an upgrade is needed) over the next 10 years. His calculation does not consider the costs of the new assets, and therefore results in an artificially low depreciation rate.

Q. Please explain why your recommendation is more appropriate.

A. My recommendation of 10.06% will not only recover the costs of the existing CCS assets but will also be appropriate to use for the costs of the upgrade to the CCS system, which Mr. Kollen agrees will be in service for 10 years. Thus, the 10.06% rate I have recommended is much more appropriate than the 3.52% rate recommended by Mr. Kollen. A retirement date of 2027 will be more appropriate once the new assets are in service and can be incorporated into the calculations of the depreciation rate to use for the CCS system.

VIII. CONCLUSION

Q. IN YOUR OPINION, ARE THE DEPRECIATION RATES SET FORTH IN YOUR DEPRECIATION STUDIES THE RATES THE KENTUCKY PUBLIC SERVICE COMMISSION SHOULD ADOPT IN THIS PROCEEDING FOR KU?

A. Yes, these rates appropriately reflect the rates at which the value of LG&E and KU's assets are being consumed over their useful lives. These rates are an appropriate basis for setting electric and gas rates in this matter and for the Companies to use for booking depreciation and amortization expense going forward.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA	)	
	)	**SS:**
COUNTY OF CUMBERLAND	)	

The undersigned, **John J. Spanos**, being duly sworn, deposes and says he is Senior Vice President, for Gannett Fleming Valuation and Rate Consultants, LLC, that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John J. Spanos

John J. Spanos

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 4th day of April, 2017.

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
MEGAN LYNN WADE
Notary Public
EAST PENNSBORO TWP, CUMBERLAND COUNTY
My Commission Expires Sep 12, 2019

Megan Lynn Wade (SEAL)
Notary Public

My Commission Expires:

Sep. 12, 2019

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**)))))**	**CASE NO. 2016-00371**

REBUTTAL TESTIMONY OF
CHRISTOPHER M. GARRETT
DIRECTOR, RATES
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: April 10, 2017

Q. Please state your name, position, and business address.

A. My name is Christopher M. Garrett. I am the Director of Rates for Louisville Gas and Electric Company ("LG&E" or "Company") and Kentucky Utilities Company ("KU") and an employee of LG&E and KU Services Company, which provides services to LG&E and KU (collectively "Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What are the purposes of your rebuttal testimony?

A. The purposes of my testimony are to rebut certain revenue requirement claims made by the witness Ralph Smith for the Attorney General ("AG"), the witness Lane Kollen for Kentucky Industrial Utility Customers, Inc. ("KIUC"), Neal Townsend for The Kroger Co. ("Kroger") and the witness Jeff Pollock for Louisville/Jefferson Metro ("LJM").

Cash Working Capital

Q. Do AG witness Smith and LJM witness Pollock claim an adjustment should be made to LG&E's cash working capital allowance?

A. Yes. LJM witness Pollock argues the cost of fuel should be excluded from the cash working capital allowance. AG witness Smith contends the cash working capital should be adjusted to reflect the impact of his additional adjustments to O&M for other issues. AG witness Smith also argues the Commission should require LG&E to file a lead-lag study in its next rate case. Their claims should be rejected.

Q. What method of property valuation did LG&E recommend to the Commission in this case?

A. As discussed in my direct testimony, LG&E has provided the Commission with both a rate base valuation method and a capitalization valuation method and recommended the revenue requirements for electric operations to be determined using the capitalization method consistent with LG&E's rate cases for many years.

An adjustment for cash working capital is a component of rate base, but not capitalization. The Commission does not recognize a cash working capital adjustment in the calculation of capitalization. Therefore, adjusting cash working capital in rate base in this case is only relevant in calculating the allocation of electric and gas capitalization in calculating the revenue requirements.

Q. Is Mr. Pollock's argument consistent with the Kentucky Commission's orders involving the Companies' rate cases?

A. No. For many years, the Commission has consistently found LG&E's revenue requirements for electric operations should be determined by applying the overall cost of capital to the gas or electric capitalization. [1] And as I demonstrated in my data response, the Kentucky Commission has consistently found that the use of the 45 day or 1/8th formula method to determine a utility's cash working capital allowance is appropriate and reasonable and is an acceptable alternative to a lead-lag study.[2] In reliance on this precedence LG&E used the 1/8 formula rate in lieu of a detailed lead-lag study to calculate the working cash capital component of its rate base valuation submitted with its application. Lead-lag studies in contrast are more time consuming and costly.

Q. Are the authorities cited by Mr. Pollock in his testimony relevant for purposes of determining the ratemaking issues associated with cash working capital?

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[1] *In the Matter of: Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company,* Case No. 90-158 Order, p. 5 (September 30, 1991).
[2] LG&E Response to AG Data Request No. 1-18

A. No. Unlike other jurisdictions which are limited to the rate base method of valuation for purposes of setting the revenue requirement, the Commission in Kentucky has the option of selecting between rate base and capitalization valuation methods.[3] The five authorities cited by Mr. Pollock in his testimony at page 31 reflect state commissions and Federal Energy Regulatory Commission (FERC) that use the rate base method for determining the revenue requirements. The Commission is not restricted by the approaches other regulatory commissions have employed using the rate base method to determine revenue requirements.

Q. Does Mr. Pollock's argument have other flaws?

A. Yes. Mr. Pollock fails to recognize the carrying cost for fuel expense and fuel inventory is not recovered through the fuel adjustment clause mechanism. Mr. Pollock's adjustment, even if appropriate for the calculation of the revenue requirement, would cause LG&E's shareholders to sustain the carrying cost of fuel expense – a prudent expense incurred to provide service.

The utilization of capitalization for valuation purposes addresses the extent to which the Company funds its working capital. This is consistent with the overall balance sheet approach for evaluating cash working capital in a revenue requirement calculation.[4]

Q. Does AG witness Mr. Smith also propose adjustments to cash working capital?

A. Yes. Mr. Smith proposes adjustments to LG&E's capitalization valuation for gas and electric operations to reflect the impact of his additional recommended adjustments to LG&E's operating expenses for gas and electric operations. As discussed in LG&E's

[3] KRS 278.290(2); 807 KAR 5:001 Section 16 (6)(c) and (f).
[4] *Rate Case and Audit Manual*, p. 20 NARUC Staff Subcommittee of Accounting and Finance (Summer 2003)

rebuttal testimony, LG&E disputes AG witness Mr. Smith's proposed adjustments to LG&E's operating expenses for gas and electric operations. Accordingly, Mr. Smith's cash working capital adjustments to LG&E's capitalization valuation for gas and electric operations should be denied.

Q. Does LG&E agree with AG witness Mr. Smith's recommendation that the Commission require LG&E to file a lead-lag study in the next rate case to determine the cash working capital requirement?

A. No. As I explained in the response to AG Initial Requests for Information, Question No. 18, the Commission has consistently found that the use of the 1/8th formula is appropriate and reasonable and is an acceptable alternative to a lead-lag study. LG&E has followed this well-established policy and used the 45 day or 1/8th formula method to determine its cash working capital allowance for many years in its regulatory filings due to the cost and burden of performing a lead-lag study. AG witness Smith's testimony fails to affirmatively demonstrate the costs and burdens of a lead-lag study merit such an effort and a departure from the Commission's well-established policy.

Scheduled Outages

Q. Do KIUC witness Kollen and Kroger witness Townsend claim a normalization adjustment should be made to LG&E's revenue requirement for scheduled generation outage expense?

A. Yes. Both assert that the planned generation outage expense in the test year does not represent the going forward level of this expense based on historical data. KIUC witness Kollen claims the Commission should adjust the generation outage expense in the test year by "normalizing" or adjusting the forecast expense by substituting a five-year historical average for the amount LG&E has estimated for its budget in the test year. Kroger witness Townsend makes a similar claim but uses a four-year average, excluding the planned outage expense for retired units Cane Run 4, 5 and 6 and including the average planned outage expense for Cane Run 7 for years 2016 through 2019.

Q. Does LG&E agree with the assertion that the test year amount of planned generation outage expense is unreasonable when compared to the historical amounts?

A. No. As discussed in the testimony of Mr. Bellar, the forecasted amount of planned outage expense is a reasonable and a reliable estimate included in LG&E's budget used by management for the electric operations. And, as Mr. Bellar explains, the historic generation outages expenses are not indicative of the expenses LG&E expects to incur through June 30, 2018 and going forward thereafter.

Q. Do the intervenors dispute the business processes used by LG&E to calculate the planned outage expense included in the test period?

A. No. They do not dispute LG&E's budgeting process used to arrive at the planned outage expense and make no affirmative showing that the planned outage expense in the test year is unreasonable per se. They argue that the forecasted amount is too high when compared to four year or five year historical amounts. As explained in Mr. Bellar's rebuttal, the four-year period selected by the Kroger witness and the five-year period selected by the KIUC witness do not accurately reflect the eight year maintenance cycle the Companies used to maintain their generation fleet. And as Mr. Bellar further explains in his rebuttal testimony, the outages in the past cannot be reasonable compared to the outages in the future because of the additional environmental control equipment now installed at each generation station. As a result, the outages are reasonably expected to last longer, be more complex, and thus, cost more than the outages did in the past. Indeed eight historical years of planned outage operation and maintenance expense does not replicate the change in composition and utilization within the fleet going forward. Finally, noticeably absent is any adjustment for inflation in their recommended normalization adjustments.

Q. Does KIUC witness Kollen identify any rate cases in which he has made a like recommendation?

A. Yes, Mr. Kollen has made a similar claim in the Companies' 2012 rate cases and one other case in Florida. He could not provide any decision where a commission adopted his recommendation.[5]

Q. Have the Commission and the Companies generally rejected normalization adjustments like those Messrs. Kollen and Townsend present for planned generation expense?

A. Yes. The Commission and the Company historically have not used normalization of operations and maintenance expenses for ratemaking purposes because such adjustments are susceptible to manipulation by the periods chosen or the data included for the adjustment. Allowing such selective and result-oriented adjustments would give rise to a series of selective adjustments the purpose of which would be to try to offset one another for the benefit of either the customer or the shareholders.

[5] KIUC Response to Commission Staff Data Request No. 8

It is for this good reason that the Commission has declined to allow such selective adjustments in the past; the exceptions are only for good cause, such as for storm damages and injuries and damages. Normalization adjustments are an exception to the widely recognized principle that a utility may request pro forma adjustments to ensure fair, just and reasonable rates based on the test period. The normalization concept is susceptible to being manipulated to achieve a certain outcome. Approval of this proposed adjustment would be a significant change to the established rate-making process.

Q. Do normalization adjustments introduce greater subjectivity into the ratemaking process?

A. Yes. *All* normalization adjustments introduce subjectivity into the rate case process that would not otherwise exist because every normalization adjustment is based upon a time period typically selected on the basis of judgment. For example, in the present case Mr. Kollen proposes a five-year historical average while Kroger witness Townsend uses a four-year average, excluding the planned outage expense for Cane Run Units 4, 5 and 6 and including the average planned outage for Cane Run 7 for years 2016 through 2019. Mr. Kollen's normalization adjustment is overstated because it excludes Cane Run 7. And, as Mr. Bellar explains in his rebuttal testimony, neither period correlates to the Company's eight-year maintenance schedule going forward.

Subjectivity and the risk of selective manipulation are inextricably entangled with normalization adjustments. As such, normalization adjustments should be reserved only for those rare categories of expense, such as storm damage, which vary greatly from year to year based upon events that are largely outside of the Company's control. Without the strict limitations on the use of normalization adjustments, the record can become filled with pro forma adjustments based on selective averages.

Q. What is your recommendation regarding outage normalization?

A. For the reasons stated above, it is my recommendation that the Commission deny the KIUC and Kroger adjustments to normalize planned generation outage expense.

As discussed, the Companies recognize that outage expense may vary from period to period given the eight year cycle and nature of the work. However, the Companies are unable to capitalize these costs absent the Commission granting deferral accounting treatment.

<u>Advanced Metering Systems</u>

Q. Does LG&E agree with the claims by AG witness Smith and KIUC witness Kollen concerning the Companies proposed investment in advanced metering systems ("AMS")?

A. No. AG witness Smith claims adjustments should be made to LG&E's capitalization and net operating income for gas and electric operations to reflect AG's witness Alvarez's recommendation that the Commission reject LG&E's proposed investment in AMS. KIUC witness Kollen asserts criticisms against AMS that are comparable to AG's witness Alvarez's arguments, and like AG witness Smith, claims adjustments should be made to LG&E's capitalization and net operating income for gas and electric operations to reflect this position. For the reasons presented in the rebuttal testimony of Mr. Malloy and Mr. Bellar, LG&E disputes the criticisms AG's witness Alvarez and KIUC's witness Kollen of the AMS proposal and continues to propose the prudent investment in AMS. Accordingly, LG&E recommends the Commission reject the ratemaking adjustments proposed by AG witness Smith and KIUC witness Kollen.

Q. Does LG&E agree with the claims by LJM witness Pollock concerning the Company's proposed investment in AMS?

A. No. In contrast to the arguments against AMS asserted by AG witness Alvarez and KIUC witness Kollen, LJM witness Pollock's testimony does not contain any criticism of LG&E's cost-benefit analysis. Instead, LJM witness Pollock's testimony accepts LG&E's cost benefit analysis for the purpose of asserting a claim that the projected AMS benefits should offset the AMS cost for ratemaking purposes. His recommendation violates the fundamental matching principal for ratemaking by mismatching the timing of the costs with the benefits. The benefits necessarily will not be achieved concurrently with the investment in AMS, but over time as the AMS is fully deployed. Mr. Pollock's recommendation however includes estimated future benefits to offset current costs. In effect, Mr. Pollock's claim in effect pulls future benefits back to offset current costs. This is contrary to Kentucky's ratemaking approach to the recovery of capital investments and specifically the Commission's consistent use of Construction Work in Progress in ratemaking for many years for LG&E. Furthermore, Mr. Pollock's recommendation does not recognize that benefits associated with fuel savings from non-technical losses or ePortal benefits will naturally flow through to customers via the monthly Fuel Adjustment Clause mechanism as described in Mr. Conroy's rebuttal testimony Therefore, for these reasons, Mr. Pollock's recommendation should be rejected.

Transmission Plant

Q. Does LG&E agree with the claims by AG witnesses concerning LG&E's proposed investment in transmission?

A. No. For the reasons presented in the rebuttal testimony of Lonnie Bellar, LG&E disputes the contentions by AG witness Holloway concerning LG&E's proposed capital expenditures on transmission. Notwithstanding AG witness Holloway's arguments, I note that AG witness Smith does not propose any associated ratemaking adjustments.

Distribution Automation Project

Q. Does LG&E agree with the claims by AG witnesses concerning LG&E's proposed investment in distribution automation?

A. No. AG witness Smith proposes adjustments to LG&E's capitalization valuation for electric operations and depreciation expense to reflect the impact of AG witness Holloway's recommendation opposing the distribution automation project. As discussed in the rebuttal testimony of John Wolfe, LG&E disputes AG witness Holloway's argument against the proposed investment in distribution automation. Accordingly, Mr. Smith's adjustments to LG&E's capitalization valuations for electric operations and related depreciation expense should be denied.

Transmission Vegetation Management

Q. Does LG&E agree with the claims by AG witness Smith and KIUC witness Kollen concerning the Companies proposed transmission vegetation management plan?

A. No. AG witness Smith claims adjustments should be made to LG&E's net operating income for electric operations to reflect his assessment that LG&E's transmission vegetation management plan and associated expenditures are not necessary. In contrast to AG witness Smith's testimony, AG witness Holloway states he is not recommending any changes to the proposed transmission vegetation management plan.[6] He even suggests that LG&E's proposed change from a reactive transmission vegetation management plan to a proactive 5-year cycle plan may not be enough and more may be required. AG witness Smith and AG witness Holloway directly contradict each other on this issue.

KIUC witness Kollen asserts criticisms against the transmission vegetation management that are comparable to AG witness Smith's argument on the need to increase transmission vegetation management.

For the reasons presented in the rebuttal testimony of Mr. Bellar, LG&E disputes the criticisms AG witness Smith and KIUC witness Kollen on the need to increase transmission vegetation management and related expenditures and the criticism of AG witness Holloway that LG&E should increase its vegetation management plan beyond the proposed five-year cycle. Accordingly, LG&E recommends the Commission reject the ratemaking adjustments proposed by AG witness Smith and KIUC witness Kollen.

Regulatory Asset Amortization

Q. Does LG&E agree with the adjustments proposed by AG witness Smith and KIUC witness Kollen concerning the amortization of regulatory assets?

A. No. AG witness Smith and KIUC witness Kollen recommend the Commission reset the amortization periods for various regulatory assets shown in the Company's

[6] Direct Testimony of Larry Holloway, p. 13.

response to KIUC 2-8. AG witness Smith recommends the balances associated with the 2011 summer storm and rate case expenses regulatory assets be amortized over a two-year period. KIUC witness Kollen recommends these balances be amortized over a three-year period. LG&E generally opposes extending the amortization periods for these expenses in a forecasted test year. For example, the three-year proposal by KIUC witness Kollen is too long and is unreasonable as it extends the amortization period for prior rate case expenses from 3 years to 5 years and the 2011 summer storm from 5 years to 7.5 years.

<u>Regulatory Mechanisms (GLT and OSS)</u>

Q Does LG&E agree with AG witness Smith's recommendations concerning the gas line tracker or off-system sales mechanisms?

A. No. Mr. Holloway argues the gas line tracker should be discontinued in order to create more regulatory lag for LG&E's recovery of capital investment to improve and maintain the safe operation of the gas distribution system. AG witness Smith recommends an adjustment to LG&E's gas revenue requirement to include the costs recovered through the gas line tracker in the base rates for gas service. For the reasons presented in the rebuttal testimony of Mr. Bellar, the Commission should reject the AG's argument and approve the proposed expansion and continuation of the gas line tracker.

In contrast, Mr. Smith also claims the Off-System Sales mechanism should be continued, but argues the sharing allocation of 75% for customers and 25% for the Company should be modified to a 90-10 ratio. The mechanism and current ratio of 75-25 are the products of the Commission-approved settlement reached among all the parties, including the AG in LG&E's last rate case.[7] Mr. Smith's testimony fails to acknowledge this fact and offers no compelling reason to change the existing allocation or any basis of support to show that providing the Company with only 10% of the margins is a sufficient incentive or reasonable allocation.

KIUC 2% Property Tax Reduction Claim

Q. Does LG&E agree with KIUC witness Kollen's recommendation to disallow the 2% escalation of property taxes?

A. No. KIUC witness Kollen asserts the 2% used by LG&E to escalate the property taxes in the forecasted test period is an unsupported assumption and recommends disallowing the escalation unless the Companies present support. His assertion is not correct. It is not an unsupported assumption.

Rebuttal Exhibit CMG-1 shows the average rates for local taxing jurisdictions in Kentucky for the past 5 years. These rates were taken directly from the published tax rates on the Kentucky Department of Revenue's website. Rebuttal Exhibit CMG-2 contains the published tax rates from the Kentucky Department of Revenue's website. The county and school tax rates have a five-year average of 1% to 3%. All of the Companies' property is subject to Kentucky county and school taxes. Although the city and special tax rates remain flat over the past 5 years, not all of the Companies' property falls within those taxing jurisdictions.

In my opinion, based on this evidence the 2% local tax escalation used by the Companies for the forecasted test period is reasonable and supportable.

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[7] *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates*, Case No. 2014-00372 Order (June 30, 2015)(Settlement Agreement 2.6 Off-System Sales ("OSS") Tracker)

Depreciation Reserves

Q. Does LG&E agree with LJM witness Pollock's recommendation to reduce the Company's revenue deficiencies by amortizing the so-called surplus depreciation reserves?

A. No. LJM witness Pollock asserts LG&E "has accumulated a surplus in its deprecation reserve and argues the surplus should be amortized over a five-year period to reduce LG&E's electric revenue deficiency by $12.9 million and gas revenue deficiency by $4.2 million. Mr. John Spanos rebuts this recommendation by demonstrating that a depreciation reserve variance is not unusual or an indication that customers have been over- or undercharged and that LJM witness Pollock's recommendation violates the matching principle, creating intergenerational inequities and providing unjustified benefits to current customer and leaving future customers with higher costs.

Q. Do you have any comments from a Kentucky regulatory perspective?

A. Yes. A consumer advocate like LJM witness Pollock may focus on keeping depreciation expense low, in an effort to reduce rates for the present. Over the life of the assets, however, his strategy doesn't work. Lower depreciation expense is exactly offset by higher net plant, causing customers to pay higher return and taxes on that net plant, such that on a present value basis, the total cost paid by ratepayers remains the same over the life of any asset. Shifts like this proposal in depreciation policies can affect the timing of cost recovery, but not the magnitude of cost recovery. In other words, it is a matter of paying now, or paying more (in nominal value terms) later. And paying more later is contrary to the Kentucky Commission's historic policies and orders.

LJM witness Pollock's claim is simply a short-term, results-oriented recommendation that is inconsistent with established ratemaking principles of this Commission. The claim is made without any apparent concern for the effect of this treatment on the Companies' cash flow, capital needs, or financial position or the impact on customers in the future. As Mr. Arbough's rebuttal points out, the deferral of the recovery of prudently incurred costs may result in higher interest rates on future debt issuances.

Q. Do you agree with LJM witness Pollock's calculation of this surplus depreciation adjustment?

A. No. Mr. Pollock is inconsistent in the application of his proposed adjustment as it relates to the reserve imbalance associated with common plant. Mr. Pollock includes an adjustment for common plant for gas operations but not electric operations. This inconsistent application further gives the impression the proposed adjustment is results-oriented.

Plant Demolition

Q. Does the Company agree with KIUC witness Kollen's recommendations concerning recovery of plant demolition costs through a retirement rider?

A. No. While this is an interesting proposition, the Company believes recovery through depreciation expense in base rates is more appropriate. Terminal net negative salvage should be a component of the Company's depreciation rates as discussed in the rebuttal testimony of Mr. Spanos.

Uncollectibles Expense

Q. Does the Company agree with AG witness Smith's uncollectibles expense recommendation?

A. No. Except to reflect changes in the law, the Commission's regulations do not permit revisions to the forecast except to correct mathematical errors.[8] His recommendation is another example of a result-oriented adjustment. Furthermore, Mr. Smith's electric operations uncollectibles expense adjustment is incorrect as he applied the five-year average to *Adjusted* Jurisdictional revenues rather than *Unadjusted* Jurisdictional revenues as shown in the excel workbooks filed with his testimony. Uncollectibles expense associated with ECR, FAC and DSM mechanism revenue is recovered through base rates.

For gas operations, Mr. Smith's uncollectibles expense adjustment is also incorrect as he applied the five-year uncollectibles average to A*djusted* Jurisdictional revenues rather than *Unadjusted* Jurisdictional revenues less *GSC* revenues[9]. Uncollectibles expense associated with DSM and GLT mechanism revenue is recovered through base rates. Uncollectibles expense associated with the GSC mechanism is recovered directly through the GSC mechanism.

Q. Does the Company agree with AG witness Smith's gross revenue conversion factor recommendation?

A. No. For the reason discussed above, the Company opposes updating the five-year uncollectibles expense average used in the gross revenue conversion factor calculation.

Q. Does this conclude your testimony?

A. Yes, it does.

[8] 807 KAR 5:001 Section 16 8. (d)

[9] Unadjusted Total Company Sales to Ultimate Consumers per Schedule C-2.1 of $315,902,323 less GSC Sales to Ultimate Consumers of $135,270,880 per Schedule D-2, Column Adj. 3.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Christopher M. Garrett**, being duly sworn, deposes and says that he is Director – Rates for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Christopher M. Garrett

Christopher M. Garrett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of April 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

Rebuttal Exhibit CMG-1
Average Rates

Kentucky Property Tax Rates
Average Local Property Tax Rates
Past 5 Years

	Real Estate Rates (cents per $100 of assessed value)						Tangible Rates (cents per $100 of assessed value)					
	2011	2012	2013	2014	2015	2016	2011	2012	2013	2014	2015	2016
Average Rates:												
COUNTY	29.03630	29.38850	29.99170	30.64370	31.52390	31.94870	37.09550	36.89190	37.04150	37.57150	38.42700	38.58320
SCHOOL	55.75010	56.80220	58.37770	60.33540	61.92530	63.07140	55.75010	56.79610	58.42680	60.37640	61.98650	63.22480
CITY	22.05050	22.13790	22.38590	22.39700	22.48350	22.54540	28.97470	28.47840	28.67760	28.63290	28.32980	28.46380
SPECIAL	10.21580	10.22080	10.25710	10.26400	10.26410	10.30650	10.48120	10.41070	10.44610	10.41550	10.41340	10.55800
Percent Increase:		2012	2013	2014	2015	2016		2012	2013	2014	2015	2016
COUNTY		1%	2%	2%	3%	1%		-1%	0%	1%	2%	0%
SCHOOL		2%	3%	3%	3%	2%		2%	3%	3%	3%	2%
CITY		0%	1%	0%	0%	0%		-2%	1%	0%	-1%	0%
SPECIAL		0%	0%	0%	0%	0%		-1%	0%	0%	0%	1%

	Real Estate 5 Year % Increase	Real Estate 5 Year Average	Tangible 5 Year % Increase	Tangible 5 Year Average
COUNTY	10%	2%	4%	1%
SCHOOL	13%	3%	13%	3%
CITY	2%	0%	-2%	0%
SPECIAL	1%	0%	1%	0%

SOI: Kentucky Department of Revenue, Property Tax Rate Books.

Rebuttal Exhibit CMG-2
Published Tax Rates

2016

TABLE II
AVERAGE LOCAL PROPERTY TAX RATES

Tax rates are expressed in cents per $100 of assessed value.

TYPE OF DISTRICT CLASS OF PROPERTY	TAX RATE *	NO. DISTRICTS REPORTING
COUNTIES		
Average Real Estate Rate	31.9487 ✓	120
Average Tangible Rate	38.5832 ✓	120
Average Motor Vehicle Rate	24.9274	120
CITIES		
Average Real Estate Rate(Zero Rates Excluded)	22.5454 ✓	403
Average Real Estate Rate(Zero Rates Included)	22.1605	410
Average Tangible Rate(Zero Rates Excluded)	28.4638 ✓	298
Average Tangible Rate(Zero Rates Included)	20.6883	410
Average Motor Vehicle Rate(Zero Rates Excluded)	24.9011	274
Average Motor Vehicle Rate(Zero Rates Included)	16.6412	410
SCHOOL DISTRICTS		
Average Real Estate Rate	63.0714 ✓	178
Average Tangible Rate	63.2248 ✓	178
Average Motor Vehicle Rate	56.0843	178
SPECIAL TAX DISTRICTS		
Average Real Estate Rate(Zero Rates Excluded)	10.3065 ✓	243
Average Real Estate Rate(Zero Rates Included)	10.2224	245
Average Tangible Rate(Zero Rates Excluded)	10.558 ✓	157
Average Tangible Rate(Zero Rates Included)	6.7657	245
Average Motor Vehicle Rate(Zero Rates Excluded)	10.0983	151
Average Motor Vehicle Rate(Zero Rates Included)	6.2239	245

2015

TABLE II
AVERAGE LOCAL PROPERTY TAX RATES

Tax rates are expressed in cents per $100 of assessed value.

TYPE OF DISTRICT CLASS OF PROPERTY	TAX RATE *	NO. DISTRICTS REPORTING
COUNTIES		
Average Real Estate Rate	31.5239 ✓	120
Average Tangible Rate	38.427 ✓	120
Average Motor Vehicle Rate	24.8092	120
CITIES		
Average Real Estate Rate(Zero Rates Excluded)	22.4835 ✓	405
Average Real Estate Rate(Zero Rates Included)	22.2093	410
Average Tangible Rate(Zero Rates Excluded)	28.3298 ✓	300
Average Tangible Rate(Zero Rates Included)	20.7291	410
Average Motor Vehicle Rate(Zero Rates Excluded)	24.9053	273
Average Motor Vehicle Rate(Zero Rates Included)	16.5833	410
SCHOOL DISTRICTS		
Average Real Estate Rate	61.9253 ✓	178
Average Tangible Rate	61.9865 ✓	178
Average Motor Vehicle Rate	55.9994	178
SPECIAL TAX DISTRICTS		
Average Real Estate Rate(Zero Rates Excluded)	10.2641	243
Average Real Estate Rate(Zero Rates Included)	10.2221	244
Average Tangible Rate(Zero Rates Excluded)	10.4134	157
Average Tangible Rate(Zero Rates Included)	6.7004	244
Average Motor Vehicle Rate(Zero Rates Excluded)	10.0661	152
Average Motor Vehicle Rate(Zero Rates Included)	6.2707	244

2014

TABLE II
AVERAGE LOCAL PROPERTY TAX RATES

Tax rates are expressed in cents per $100 of assessed value.

TYPE OF DISTRICT CLASS OF PROPERTY	TAX RATE *	NO. DISTRICTS REPORTING
COUNTIES		
Average Real Estate Rate	30.6437 ✓	120
Average Tangible Rate	37.5715 ✓	120
Average Motor Vehicle Rate	24.6404	120
CITIES		
Average Real Estate Rate(Zero Rates Excluded)	22.397 ✓	404
Average Real Estate Rate(Zero Rates Included)	22.0155	411
Average Tangible Rate(Zero Rates Excluded)	28.6329 ✓	299
Average Tangible Rate(Zero Rates Included)	20.8303	411
Average Motor Vehicle Rate(Zero Rates Excluded)	24.8764	272
Average Motor Vehicle Rate(Zero Rates Included)	16.4632	411
SCHOOL DISTRICTS		
Average Real Estate Rate	60.3354 ✓	178
Average Tangible Rate	60.3764 ✓	178
Average Motor Vehicle Rate	56.0966	178
SPECIAL TAX DISTRICTS		
Average Real Estate Rate(Zero Rates Excluded)	10.264 ✓	244
Average Real Estate Rate(Zero Rates Included)	10.264	244
Average Tangible Rate(Zero Rates Excluded)	10.4155 ✓	156
Average Tangible Rate(Zero Rates Included)	6.6591	244
Average Motor Vehicle Rate(Zero Rates Excluded)	10.044	151
Average Motor Vehicle Rate(Zero Rates Included)	6.2158	244

2013

TABLE II
AVERAGE LOCAL PROPERTY TAX RATES

Tax rates are expressed in cents per $100 of assessed value.

TYPE OF DISTRICT CLASS OF PROPERTY	TAX RATE *	NO. DISTRICTS REPORTING
COUNTIES		
Average Real Estate Rate	29.9917	120
Average Tangible Rate	37.0415	120
Average Motor Vehicle Rate	24.4223	120
CITIES		
Average Real Estate Rate(Zero Rates Excluded)	22.3859	403
Average Real Estate Rate(Zero Rates Included)	21.8969	412
Average Tangible Rate(Zero Rates Excluded)	28.6776	300
Average Tangible Rate(Zero Rates Included)	20.8817	412
Average Motor Vehicle Rate(Zero Rates Excluded)	24.8893	272
Average Motor Vehicle Rate(Zero Rates Included)	16.4317	412
SCHOOL DISTRICTS		
Average Real Estate Rate	58.3777	179
Average Tangible Rate	58.4268	179
Average Motor Vehicle Rate	55.5682	179
SPECIAL TAX DISTRICTS		
Average Real Estate Rate(Zero Rates Excluded)	10.2571	246
Average Real Estate Rate(Zero Rates Included)	10.2571	246
Average Tangible Rate(Zero Rates Excluded)	10.4461	162
Average Tangible Rate(Zero Rates Included)	6.8791	246
Average Motor Vehicle Rate(Zero Rates Excluded)	10.0109	151
Average Motor Vehicle Rate(Zero Rates Included)	6.1449	246

2012

TABLE II
AVERAGE LOCAL PROPERTY TAX RATES

Tax rates are expressed in cents per $100 of assessed value.

TYPE OF DISTRICT CLASS OF PROPERTY	TAX RATE *	NO. DISTRICTS REPORTING
COUNTIES		
Average Real Estate Rate	29.3885 ✓	120
Average Tangible Rate	36.8919 ✓	120
Average Motor Vehicle Rate	24.3884	120
CITIES		
Average Real Estate Rate(Zero Rates Excluded)	22.1379 ✓	407
Average Real Estate Rate(Zero Rates Included)	21.8692	412
Average Tangible Rate(Zero Rates Excluded)	28.4784 ✓	302
Average Tangible Rate(Zero Rates Included)	20.8749	412
Average Motor Vehicle Rate(Zero Rates Excluded)	24.8229	272
Average Motor Vehicle Rate(Zero Rates Included)	16.3879	412
SCHOOL DISTRICTS		
Average Real Estate Rate	56.8022 ✓	179
Average Tangible Rate	56.7961	179
Average Motor Vehicle Rate	55.5274	179
SPECIAL TAX DISTRICTS		
Average Real Estate Rate(Zero Rates Excluded)	10.2208 ✓	248
Average Real Estate Rate(Zero Rates Included)	10.2208	248
Average Tangible Rate(Zero Rates Excluded)	10.4107 ✓	162
Average Tangible Rate(Zero Rates Included)	6.8005	248
Average Motor Vehicle Rate(Zero Rates Excluded)	10.0332	152
Average Motor Vehicle Rate(Zero Rates Included)	6.1494	248

2011

TABLE II
AVERAGE LOCAL PROPERTY TAX RATES

Tax rates are expressed in cents per $100 of assessed value.

TYPE OF DISTRICT CLASS OF PROPERTY	TAX RATE *	NO. DISTRICTS REPORTING
COUNTIES		
Average Real Estate Rate	29.0363	120
Average Tangible Rate	37.0955	120
Average Motor Vehicle Rate	24.1614	120
CITIES		
Average Real Estate Rate(Zero Rates Excluded)	22.0505	409
Average Real Estate Rate(Zero Rates Included)	21.8369	413
Average Tangible Rate(Zero Rates Excluded)	28.9747	300
Average Tangible Rate(Zero Rates Included)	21.047	413
Average Motor Vehicle Rate(Zero Rates Excluded)	24.6903	273
Average Motor Vehicle Rate(Zero Rates Included)	16.3207	413
SCHOOL DISTRICTS		
Average Real Estate Rate	55.7501	179
Average Tangible Rate	55.7911	179
Average Motor Vehicle Rate	55.5073	179
SPECIAL TAX DISTRICTS		
Average Real Estate Rate(Zero Rates Excluded)	10.2158	247
Average Real Estate Rate(Zero Rates Included)	10.2158	247
Average Tangible Rate(Zero Rates Excluded)	10.4812	160
Average Tangible Rate(Zero Rates Included)	6.7894	247
Average Motor Vehicle Rate(Zero Rates Excluded)	10.0339	152
Average Motor Vehicle Rate(Zero Rates Included)	6.1747	247