LG&E and KU

Transmission System Improvement Plan Annual Report

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In Case No. 2016-00370 and Paragraph 8 of Order entered
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1. Executive Summary

In connection with their 2016 applications for adjustment of base rates and for issuance of certificates of public convenience and necessity, Kentucky Utilities Company ("KU") (Case No. 2016-00370) and Louisville Gas and Electric Company ("LG&E") (Case No. 2016-00371) submitted a spending plan for improvement of their combined transmission system. This plan, entitled the Transmission System Improvement Plan ("TSIP"), projected $108.3 Million in spending on reliability investments over a five year period from 2017-2021, and $430 Million in system integrity and modernization investments over the same time period.

In its orders entered on June 22, 2017, the Kentucky Public Service Commission ("PSC") approved stipulated settlements in both cases with certain modifications, resolving the applications filed by KU and LG&E (collectively, the "Companies"). The Orders approved the spending contained in the TSIP, and required that the Companies file an annual report starting June 1, 2018, detailing TSIP spending for the preceding reporting period, the criteria used to prioritize transmission projects, the impact on system reliability and other benefits to the Companies' customers resulting from the investments, and outlining proposed spending for the following year.[1]

This report is submitted pursuant to the PSC's directive. It shows that the Companies are following through on their proposed investments in the transmission system, both to increase the reliability of the system now, and to modernize the system to ensure it performs safely and resiliently for many years to come. The report further illustrates how the Companies are using inspection cycles and planned outages to maximize the efficiency of asset replacements and minimize impacts to customers. Improvements in reliability can already be seen for specific lines on which system infrastructure investments have been made.

The Companies anticipate that spending on certain TSIP-related programs in 2019 will exceed the forecasts made when the TSIP was first created. The current forecasts are consistent with investment plans as filed in the 2018 LG&E and KU rate cases. These increases are primarily driven by the condition of assets found during inspections and the prioritization of investments to improve and sustain reliable performance of the transmission grid. More specifically, these assets are primarily wood structures found to be deteriorated, certain types of conductor nearing end of life and experiencing loss of strength and/or corrosion and system protection components that are at end of life and at risk of operating incorrectly. The Companies are continually responding to new information and changed circumstances in

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[1] PSC Order June 22, 2017, Case No. 2016-00370, at 28-29; PSC Order June 22, 2017, Case No. 2016-00371, at 31, 35.

determining the timing and priority of these investments into the transmission system. Through flexibility and the ability to change program priorities and investments based on inspection data, risk assessment, and scheduled outages, the Companies are best able to efficiently conduct asset replacements and carry out the objectives of the TSIP: securing the existence of a modern, reliable, safe and resilient transmission system now and in the future.

2. 2018 Spending Report[2]

2.1 Overall Spending Comparison versus the 2018 KPSC Report

The following table sets forth the Companies' combined actual spending for TSIP-related improvements in 2018 versus the projections in the 2018 KPSC Report:

Table 1: LG&E and KU Combined 2018 KPSC Report Projection vs. Actual ($MM)

	2018 KPSC Report Projection	2018 Actual	Variance ($)
O&M Total:	$14.3	$14.5	$0.2
Capital Total:	$108.5	$107.3	($1.2)
Total:	$122.8	$121.8	($1)

The following tables show the same spending comparison broken down by LG&E and KU, respectively:

Table 2: LG&E 2018 KPSC Report Projection vs. Actual ($MM)

	2018 KPSC Report Projection	2018 Actual	Variance ($)
O&M Total:	$3.0	$2.7	($0.3)
Capital Total:	$19.8	$19.6	($0.2)
Total:	$22.8	$22.3	($0.5)

[2] All tables in Section 2 show a comparison between the 2018 KPSC Report projections in Case Nos. 2016-00370 and 2016-00371 and 2018 actuals.

Table 3: KU 2018 KPSC Report Projection vs. Actual ($MM)			
	2018 KPSC Report Projection	**2018 Actual**	**Variance ($)**
O&M Total:	$11.3	$11.8	$0.5
Capital Total:	$88.6	$87.7	($0.9)
Total:	$99.9	$99.5	($0.4)

As these tables reflect, combined spending for Operations & Maintenance (O&M) and capital was within one percent of 2018 KPSC Report projections.

2.2 2018 Spending on Reliability Projects

The following shows how the Companies allocated 2018 spending on reliability projects compared to 2018 projections in the 2018 KPSC Report:

Table 4: LG&E and KU Combined 2018 KPSC Report Reliability Projection vs. Actual ($MM)			
	2018 KPSC Report Projection	**2018 Actual**	**Variance ($)**
O&M for TSIP Projects (Veg. Mgmt, ,Switch Maintenance and corrosion protection)[3]	$14.3	$14.5	$0.2
Line Sectionalizing (Capital):	$11.5	$8.1	($3.4)

[3] Corrosion protection is shown as an O&M expense in Table 6 of the TSIP Document.

The Companies' spending on O&M reliability projects was very close to what the Companies projected in the 2018 KPSC Report. Spending on line sectionalizing, a capital project to improve system reliability, was lower than the Companies' projections. Prior to project execution, original estimates were evaluated with a more developed scope and timing, resulting in a more refined project estimate that was lower than originally projected. Small variances throughout a large number of projects account for the underrun.

2.3 2018 Spending on System Integrity and Modernization Projects

The following table contains a breakdown of the Companies' actual 2018 spending on system integrity and modernization projects compared to the Companies' forecast in the 2018 KPSC Report:

Table 5: LG&E and KU Combined 2018 KPSC Report System Integrity Project Forecast vs. Actual ($MM)

	2018 KPSC Report Projection	**2018 Actual**	**Variance ($)**
Line Equipment	$60[4]	$62.7	$2.7
Underground Lines	$5.4	$4.6	(0.8)
Substation Equipment	$17.9[5]	$19.8	$1.9
Substation P&C Systems	$13.6	$12	($1.6)
Total System Integrity:	**$96.9**	**$99.1**	**$2.2**

As summarized in this table, total 2018 spending on transmission system integrity and modernization projects under the 2018 KPSC Report was within three percent of the Companies' projections from the prior year's report submitted in June of 2018. The additional spend allocated to Substation Equipment was due to additional equipment

[4] Separately shown as line equipment, line switches, and overhead lines in Table 6 of the TSIP Document.

[5] Separately shown as circuit breakers, insulators, line arresters, and coupling capacitors in Table 6 of the TSIP Document.

identified in need of replacement based on condition during project scoping, and then taking advantage of the scheduled outage opportunities to replace those assets.

2.3.1. Line Equipment

Historically, the Companies conducted system-wide aerial inspections for damage to or deterioration of poles in the transmission system. Starting in 2013, in part in response to evolving Commission regulations regarding inspections, the Companies began performing more detailed pole inspections and initiated a cycled approach to those inspections. Wood poles are now inspected every six years and steel poles are inspected every twelve years. Pole inspections include detailed visual observation, sounding, and, when possible, climbing of the poles to observe their condition.

The more detailed ground based inspections have been successful in identifying poles in need of replacement. The Companies budgeted for 920 pole replacements in calendar year 2018 based on recent inspection history. However, inspections in 2018 yielded a higher number of poles in need of replacement than planned. To manage the increased backlog for pole replacements, the Companies replaced 1000 poles in 2018 versus the planned 920 contributing to additional spending toward line equipment compared to the budget projected in the 2018 KPSC Report.

At the end of 2017, there were approximately 2,900 poles in the transmission system slated for replacement. 2018 was the final year of the first six-year cycle for wood pole replacements. Early in this second cycle of detailed pole inspections, the reject rate for inspected wood structures has remained higher than originally anticipated. Quality control checks have confirmed the inspections produce consistent results. As such the Companies will continue to need to spend more on wood structure replacement than originally anticipated.

The Companies 2018 spend for overhead lines replacement was slightly below 2018 KPSC Report projections due primarily to material and construction delays.

2.3.2. Underground Lines

The Companies' actual spending for replacement of undergrounds lines in 2018 was less than 2018 KPSC Report projections. Underground construction obstacles encountered during installation of the duct bank in downtown Lexington contributed to delays and deferred some of the planned expenses.

2.3.3. Substation Equipment

Spending on replacement of substation equipment, including circuit breakers, insulators, line arresters, and coupling capacitors exceeded 2018 KPSC Report projections by $1.8 Million in 2018. The variance was due to a holistic asset replacement strategy. Utilizing this strategy, the Companies evaluate replacements at the station level to determine the feasibility of consolidating multiple programs outlined in the TSIP into a single project. This allows equipment to be replaced in a more cost effective and efficient manner. Through this approach, the Companies utilized resources and planned outages to replace additional assets at specific locations that were planned for future years.

3. Criteria Used to Prioritize Projects

There is not a "one size fits all" approach to prioritizing reliability or system integrity projects contained in the TSIP. The Companies must be nimble and adapt their approach to asset replacement to respond to changed circumstances. For example, planned substation outages allow the Companies to accelerate replacement of equipment at that substation without causing additional impact to customers. Furthermore, overall system resiliency is best achieved when certain related equipment (such as breakers, insulators, and line arrestors) are replaced simultaneously. The Companies can maximize efficiency in asset replacement when they have flexibility to determine how such replacements are prioritized and when they occur.

Prioritization within each program or asset class depends on the impact of failure on the Companies' customers, the type of asset, the age and condition of the asset, past performance and maintenance history, or some combination of these factors. This section describes the various projects contained in the TSIP and the general criteria used to prioritize those projects.

3.1 Reliability Programs

3.1.1. Prioritizing Vegetation Management Activity

As the Companies reported in testimony and related materials filed in the 2016 rate cases, in 2016 the Companies began transitioning their line clearing and vegetation management programs on 345kV and higher lines from a just-in-time approach to a 5-year cycled approach. Starting in mid-2017, the Companies began the first cycle for lines operating below 345kV. Because the complete cycle will take five years to implement, the Companies have continued with aerial inspections to identify potential line interference and hazard trees, and those inspections are still the primary method of prioritizing vegetation management activities. Potential customer impact and the occurrence of other work, such as pole and conductor replacements, is also a factor.

Once the first five year cycle is complete, prioritization of line clearing will be based primarily on the established cycle, while off-cycle work will continue to be prioritized through inspection programs.

3.1.2. Prioritizing Line Switch Maintenance

As part of the TSIP, the Companies have established a detailed annual inspection cycle for all automated and motor operated line switches. All remaining manual switches will be inspected every other year. The results of these inspections allow the Companies to repair switches as necessary or to prioritize switches for replacement. The cycles for the inspections themselves were established based on industry best practices and the likelihood of failures for different types of equipment.

3.1.3. Prioritizing Line Sectionalizing

Line sectionalizing involves installation of in-line breakers or switches to decrease customer exposure to outages on long transmission lines with multiple load taps. Priority for lines to receive this new equipment is based on the length of the line, the total customer impact in the event of an outage, and past performance of the line in terms of outage frequency and duration.

3.2 System Integrity Programs

3.2.1. Prioritizing Line Equipment Projects

Prioritization of line equipment (including poles), line switches, and overhead lines is based primarily upon analysis of field inspection data and the condition of the asset. For example, if inspection data reveals that certain poles are in need of replacement sooner than others, those poles are targeted for replacement within six months of inspection. Poles that are in better condition but still in need of replacement are targeted on a 24-30 month time horizon. Other factors that can influence the priority of replacement of line equipment, line switches, and overhead lines are field notes captured during inspection, past performance of the circuit on which the equipment operates, extent of customer impact in the event of equipment or line failure, and other work planned on the circuit which may allow the Companies the opportunity to replace line equipment without further service interruption.

3.2.2. Prioritizing Substation Equipment Projects

Circuit breakers are mechanical switching devices subject to mechanical failure and are sometimes difficult to keep in adjustment. Replacements are prioritized using a number of factors, including past maintenance history, environmental risks (risk of oil release), age, results of diagnostic test results, and potential customer impact of breaker failure.

Substation insulators are used to isolate energized conductors and switching equipment from ground. Replacement of substation insulators contemplated by the TSIP targets both cap and pin and hollow post insulators. Cap and pin insulators typically fail when their cement joints deteriorate and allow separation of components. Most hollow post insulator failures are attributable to water ingress to the hollow portion of the insulator. Replacements are prioritized by the timing of scheduled work on related breakers, potential customer impact of failure, and in some cases, visual inspection.

Line arresters protect transmission equipment by limiting transient overvoltage typically caused by lightning strikes or switching. Porcelain or silicon carbide components on older line arresters are prone to failure and resulting outages. Replacement of line arresters is performed in connection with replacement of other substation assets and is not individually prioritized.

Coupling capacitors couple a signal from a power line carrier to the transmission line. Their failure is difficult to predict. Replacements are prioritized based primarily on customer impact of failure, age and type of equipment.

3.2.3. Prioritizing Substation Protection and Control Systems

Protection and Control (P&C) Systems refer to a class of equipment used to identify power system disturbances, stop system degradation, restore the system to a normal state, and minimize the impact of disturbance. P&C equipment is typically contained inside a substation control house and includes relay panels, remote terminal units (RTUs), power line carriers, digital fault recorders, and batteries.

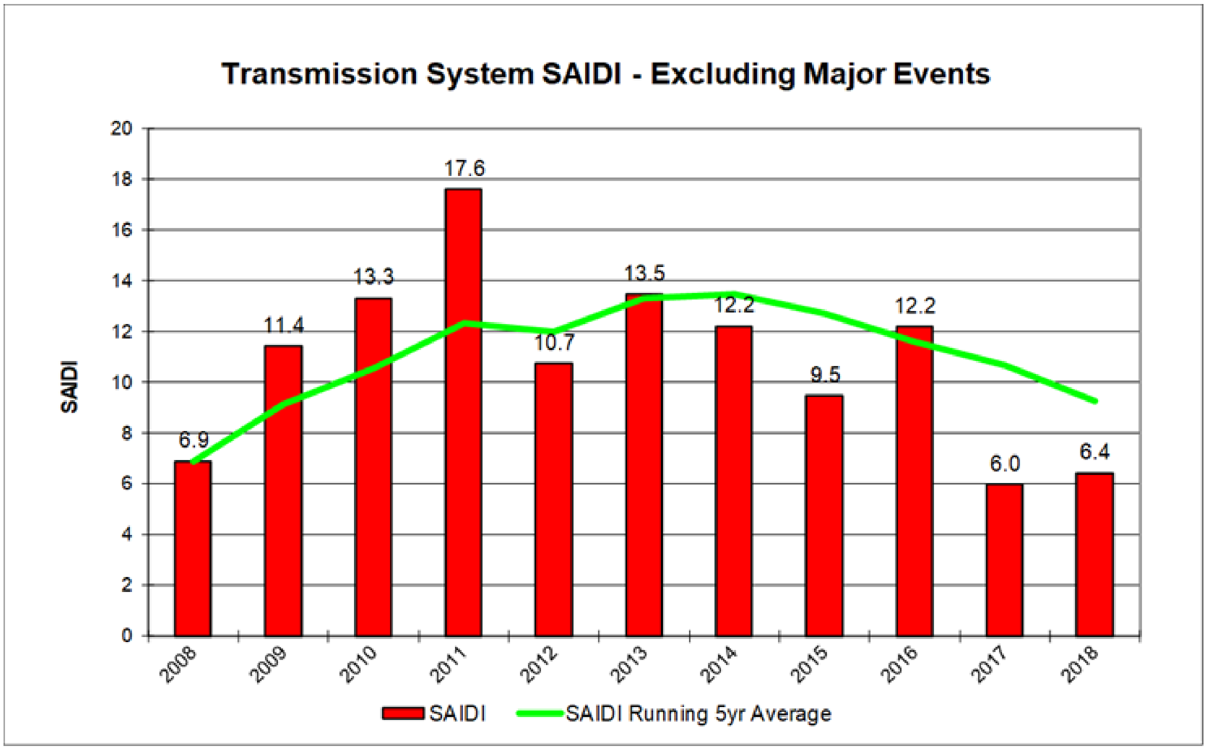
Replacement of the control house itself is prioritized based on the overall condition of the control house and the equipment inside. Replacement of relays and RTUs are prioritized primarily based on past performance. Power line carriers and digital fault recorders are replaced based on past maintenance history, and new digital fault recorders are added based on the need to improve data on a particular circuit. Batteries are replaced based upon their condition.

4. Impact on System Reliability and Other Benefits

4.1 System-Wide Reliability Performance

Transmission System Average Interruption Duration Index ("SAIDI") has been a traditional metric to track transmission reliability. SAIDI measures the average electric service interruption duration in minutes per customer for the specified period and system. Typically, major event days such as a severe wind storm are excluded from this metric. The following graphic shows the Companies' combined transmission system SAIDI for the past eleven years:

Figure 1: Combined Transmission SAIDI 2008-2018



As this figure demonstrates, the Companies' combined 2018 transmission reliability performance was favorable compared to recent years as measured by SAIDI, resulting in just 6.4 minutes of average service interruption per customer. This improved performance is despite a greater than typical level of storm activity in 2018. In fact, two of the top seven storms experienced by LG&E and KU since 2003 were in 2018. This data shows a continued positive trend in improvement of transmission system reliability, and the Companies expect that the upgrades and improvements included in the TSIP are contributing to and will continue to contribute to that positive trend.

4.2 Reliability Benefits on Specific Lines

Since 2015, the Companies have implemented and completed 58 reliability projects. These include installing eight new breakers and a total of 46 switches to improve the system's reliability by reducing overall customer exposure to outages and reducing the restoration time when an outage occurs. Out of the 46 switches, 25 are motor operated switches and 12 have Automatic Reclosing Scheme to further speed customer restoration. The Companies are continuing to invest in these types of projects in order to continue improving system performance and maintaining a high level of system reliability. The Companies have noted immediate and significant improvements in reliability resulting from TSIP investments on certain lines as described in the examples below.

4.2.1 Beattyville to West Irvine

In 2016, KU added a motor operated switch and in 2017 added automation at the Irvine tap point for this line. From 2012 until the time this switch was installed, this circuit experienced fourteen (14) sustained events and accounted for 2.7 minutes of SAIDI for an average SAIDI of 0.19 minutes per event. After these projects were completed, this circuit experienced five (5) sustained events, but collectively those events accounted for only 0.04 minutes of SAIDI impact for an average SAIDI of 0.008 minutes per event. Additionally, the combination of an auto-reclosing scheme with the motor operated switches on the line prevented a potential 1.9 minutes of SAIDI in 2018 alone.

4.2.2 Lexington Plant to Pisgah

The Lexington Plant to Pisgah line was previously KU's worst performing transmission line in terms of system outages and duration. The line experienced eleven (11) sustained events and contributed 8.6 minutes of SAIDI since 2012. In 2016, KU added two circuit breakers at the Parker's Mill station and motor operated switches at the Parker's Mill tap point. Several miles of the line were replaced and rebuilt. Since the completion of these improvements, there have been only two (2) sustained outages. Only one of those outages caused a SAIDI impact on a major event day of 0.079 minutes.

4.2.3 Rogersville to Vine Grove

The Rogersville to Vine Grove line was previously KU's third worst performing transmission line in terms of SAIDI. The line experienced ten (10) sustained events and contributed 4.04 minutes of SAIDI since 2012 for an average of 0.4 minutes per event. In 2017, KU added a motor operated switch and auto reclosing scheme at the Radcliff station. Since the completion of these improvements, there has only been one sustained outage with a SAIDI impact of 0.12 minutes. The auto reclosing scheme prevented over 4,300 customers from experiencing a sustained outage.

4.2.4 Harlan Y to Evarts to Pocket

In 2017, KU added a motor operated switch and auto reclosing scheme at the Harlan 557 Station on this line. From 2012 until the installation of this switch, the circuit experienced nine (9) sustained outages accounting for 1.17 minutes of SAIDI. Since the completion of the project, there has only been one sustained outage with a SAIDI impact of 0.075 minutes. The auto reclosing scheme restored over 1600 customers within one minute.

4.3 Reliability Benefits of Cycled Vegetation Management and Hazard Tree Removal

As set forth above, the Companies are in the midst of implementing a 5-year line clearing cycle for transmission lines. Cycled line clearing began on extra high voltage lines (345kV and 500kV) first and is now being performed on lower voltage lines (161kV, 138kV, and 69kV) as described in the TSIP. Inspections of lines which have already been cleared under the cycle reveal more uniform line clearance as compared to the previous just-in-time approach, in which significant variations in vegetation encroachment on a single line were sometimes observed. As completion of the first five-year cycle progresses, the Companies expect to see improved reliability through uniform maintenance of established transmission corridors.

In 2018 the Companies also completed hazard tree patrols on over 800 transmission miles across the transmission system. These patrols identified roughly 3,300 ash trees scheduled for removal and removed a total of 3,500 hazard trees. Hazard trees pose a risk of line interference and resulting service disruption. Early identification and removal of hazard trees improves the overall reliability of the transmission system and mitigates the risk of tree-related outages.

4.4 Other Benefits of TSIP Projects

Replacement of aging transmission assets not only contributes to system reliability now, but also improves the resiliency and reliability of the transmission system long into the future. The assets being replaced under the TSIP are nearing end of life and/or obsolete. Replacement parts for many of these aging assets are costly and difficult to obtain, and do not necessarily extend the life of the assets. Replacement assets installed under the programs outlined in the TSIP employ modern technology which enhances the overall safety and resiliency of the system. For example, replacement relays installed in the Companies' substations contain microprocessors which capture valuable data used in fault analysis and outage prevention. This equipment enables the Companies to more accurately identify a fault location and reduce the number of faults where an initiating cause cannot be identified.

Furthermore, many of the lines being improved were previously designed for medium loading under the National Electrical Safety Code ("NESC"). New equipment installed on these lines is designed for heavy loading under the NESC, improving the ability of the line to withstand weather events such as wind and ice. For example, while most of the poles being replaced on the transmission system are wood, most of the replacement poles are steel. Steel poles have a longer expected life than wood poles, are more resilient to hazards and severe weather events, and do not deteriorate like wood poles. This approach is typical in the industry for transmission structures, particularly in areas where woodpeckers are common.

Replacement of aging infrastructure also reduces the risk and potential impact of environmental contamination. Circuit breakers containing oil are being replaced with modern equipment that does not contain oil, reducing the amount of oil in the transmission system and thus reducing environmental risks posed thereby.

In summary, the investments being made consistent with the TSIP provide long lasting benefits to system resilience, public and employee safety, and operational efficiency in addition to improving overall system reliability.

5. 2019 Projected KPSC Spending

The following table shows the Companies' combined projected spend in 2019 related to programs outlined in the TSIP:

Table 6: LG&E and KU Combined KPSC Projections for 2019 ($MM)	
	Current 2019 Forecast[6]
O&M Total:	**$ 15.0**
Capital Total:	**$ 130.1**
Total:	**$ 145.7**

[6] Forecast includes actual spending through April, 2019 and projected spend for the remainder of the year.

As noted previously in this report, the 2019 projections related to the Transmission System Improvement Plan (TSIP) are expected to continue the trends referenced in the 2018 KPSC Report. Data gathered from ongoing inspections indicate the projections in the original TSIP were not enough to maintain the integrity of the Transmission system. The largest driver behind the need for increased spend is to address wood poles that are in need of replacement. The backlog of poles identified for replacement is higher than projected necessitating the need to allocate more resources to the wood pole replacement program.