LG&E and KU
Transmission System Improvement Plan Annual Report

Filed Pursuant to Paragraph 9 of Order entered June 22, 2017
In Case No. 2016-00370 and Paragraph 8 of Order entered
June 22, 2017 in Case No. 2016-00371

June 1, 2022

Prepared by:

Table of Contents

Table of Tables

Table of Figures

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 $429.5 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 final 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.

Similar to previous years, the Companies spend in 2021 for certain TSIP-related programs exceeded the forecasts made when the TSIP was first created. These TSIP 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 conductors 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.

---

[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.

The Companies are continually responding to new information and changed circumstances in determining the timing and priority of these investments into the transmission system.

TSIP O&M spend has consistently been in line with the forecasts made when the TSIP was first created due to less variables in the business plan.

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. 2021 Spending Report[2]

2.1 Overall Spending Comparison versus the 2021 KPSC Report

The following table sets forth the Companies' combined actual spending for TSIP-related improvements in 2021 versus the projections in the 2021 KPSC Report:

Table 1: LG&E and KU Combined 2021 KPSC Report Projection vs. Actual ($MM)

	2021 KPSC Report Projection	**2021 Actual**	**Variance ($)**
O&M Total:	$16.7	$16.2	($0.5)
Capital Total:	$168.4	$160.8	($7.6)
Total:	$185.1	$177.0	($8.1)

[2] All tables in Section 2 show a comparison between the 2021 KPSC Report projections in Case Nos. 2016-00370 and 2016-00371 and 2021 actuals.

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

Table 2: LG&E 2021 KPSC Report Projection vs. Actual ($MM)			
	2021 KPSC Report Projection	**2021 Actual**	**Variance ($)**
O&M Total:	$5.3	$4.2	($1.1)
Capital Total:	$30.8	$29.3	($1.5)
Total:	$36.1	$33.5	($2.6)

Table 3: KU 2021 KPSC Report Projection vs. Actual ($MM)			
	2021 KPSC Report Projection	**2021 Actual**	**Variance ($)**
O&M Total:	$11.4	$12.0	$0.6
Capital Total:	$137.6	$131.5	($6.1)
Total:	$149	$143.5	($5.5)

As these tables reflect, combined spending for Operations & Maintenance ("O&M") and capital was within five percent of 2021 KPSC Report projections. Minor variances occurred between programs, which will be explained in later sections.

2.2 *2021 Spending on Reliability Projects*

The following shows how the Companies allocated 2021 spending on reliability projects compared to 2021 projections in the 2021 KPSC Report:

Table 4: LG&E and KU Combined 2021 KPSC Report Reliability Projection vs. Actual ($MM)			
	2021 KPSC Report Projection	**2021 Actual**	**Variance ($)**
O&M for TSIP Projects (Veg. Mgmt., Switch Maintenance and corrosion protection)[3]	$16.7	$16.2	($0.5)
Line Sectionalizing (Capital):	$10.0	$7.0	($3.0)

The Companies' spending on O&M was within three percent and in line with projections provided in the 2021 KPSC Report. Variances in Line Sectionalizing (capital) spend can mainly be attributed to permitting challenges, which delayed spend in 2021.

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

2.3 *2021 Capital Spending on System Integrity and Modernization Projects*

The following table contains a breakdown of the Companies' actual 2021 spending on system integrity and modernization projects compared to the Companies' forecast in the 2021 KPSC Report:

Table 5: LG&E and KU Combined 2021 KPSC Report System Integrity Project Forecast vs. Actual ($MM)			
	2021 KPSC Report Projection	**2021 Actual**	**Variance ($)**
Line Equipment[4]	$125.5	$124.3	($1.2)
Underground Lines	$0.0	$0.0	$0.0
Substation[5] Equipment	$12.7	$11.5	($1.2)
Substation Protection & Control (P&C) Systems	$20.2	$18.0	($2.2)
Total System Integrity:	**$158.4**	**$153.8**	**($4.6)**

As summarized in this table, total 2021 spending on transmission system integrity and modernization projects under the 2021 KPSC Report was within three percent of the Companies' projections from the prior year's report submitted in June of 2021. Variances are described in the sections below.

[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.

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 wood poles in need of replacement, and the Companies continue to focus on addressing replacements in the pole backlog. The Companies budgeted and executed the replacement of 1,117 poles in calendar year 2021.

At the end of 2021, there were approximately 3,171 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 remained higher than originally anticipated; however, the reject rate has decreased midway through the second cycle. Quality control checks have confirmed the inspections produce consistent results and the Companies will continue to replace rejected wood structures, as identified, during these pole inspections.

The Companies 2021 spend for line equipment and overhead lines replacement was below the 2021 KPSC Report projections. Variances in this program can be attributed to permitting challenges, which resulted in funding shifts between years, and the reallocation of resources due to weather events in 2021.

2.3.2. Substation Equipment and Protection and Controls

The Companies 2021 spend for Substation Equipment and Protection and Controls was below the 2021 KPSC Report projections. Individual project estimates were refined throughout the year, resulting in actuals that were less than the original budgeted totals.

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) is 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 earlier. 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. The Companies are further integrating these factors into line replacement prioritization to allow more impactful equipment to be replaced sooner.

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

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.

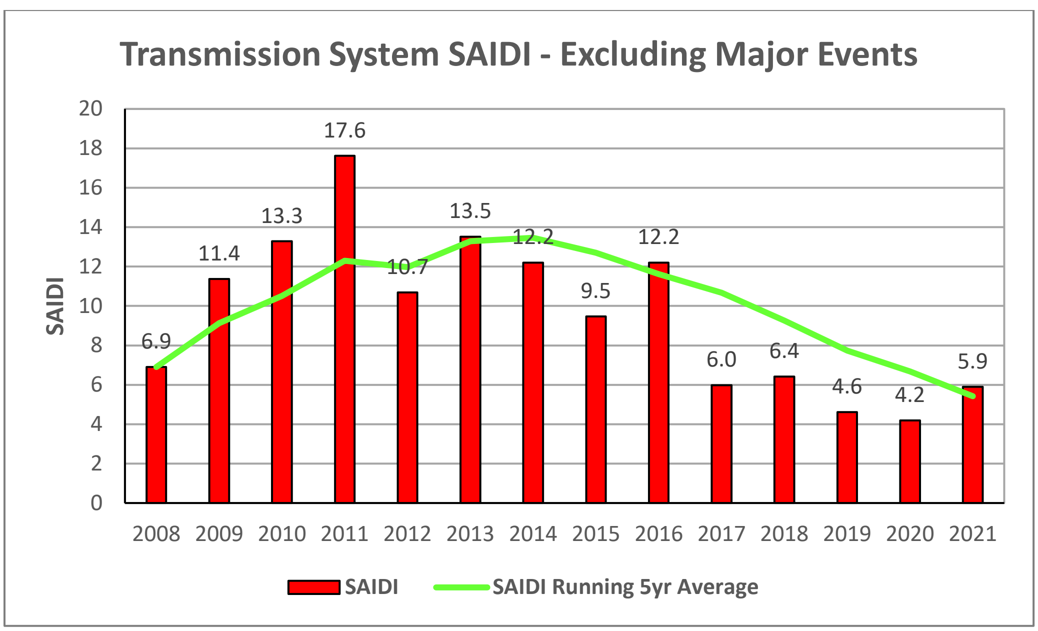
Replacement of the control house itself is prioritized based on the overall condition of the control house and the equipment inside. Replacement of relays and RTUs are prioritized primarily based on past performance. Power line carriers and digital fault recorders are replaced based on past maintenance 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 windstorm, are excluded from this metric. The following graphic shows the Companies' combined transmission system SAIDI for the past fourteen years:

Figure 1: Combined Transmission SAIDI 2008-2021



As this figure demonstrates, the Companies' combined 2021 transmission reliability performance as measured by SAIDI continues a favorable trajectory, resulting in just 5.9 minutes of average service interruption per customer. This data shows a continued downward trend in outage durations reflecting the improvement of transmission system reliability. The Companies expect that the upgrades and improvements included in the TSIP are contributing to and will continue to contribute to this trend.

Due to the record number of the transmission upgrades that occurred in 2021, a large number of customers were temporarily served by radial feeds, which left these customers more vulnerable to outages. Two extreme weather systems in 2021, lasting multiple days, resulted in lower reliability performance in 2021, compared to 2019 and 2020. Despite these challenges, the company was able to avoid interrupting over 50,000 customers and saving 0.9 minute of SAIDI as a result of the upgrades and improvements included in the TSIP.

4.2 Reliability Benefits on Specific Lines

Since 2015, the Companies have implemented and completed 163 reliability projects. These include installing 15 new breakers, 122 switches and 26 other projects that consist of line fault indicators, digital fault recorders and remote terminal units. These projects have improved the system's reliability by reducing overall customer exposure to outages and reducing the restoration time when an outage occurs. Out of the 122 switches, 100 are motor operated switches and 56 have Automatic Reclosing Scheme ("ARS") to further speed customer restoration. The Companies are continuing to invest in these types of projects in order to enhance system performance and maintain a high level of system reliability while also enhancing data collection and analytic capabilities.

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

KU added a motor operated switch in 2016 and implemented auto-reclosing scheme in 2017 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 0.2 minutes per event. After these projects were completed, this circuit experienced eleven (11) sustained events, but collectively those events accounted for only 0.25 minutes of SAIDI impact for an average SAIDI of 0.02 minutes per event. Additionally, the combination of the auto-reclosing scheme with the motor operated switches on the line prevented a potential three (3) minutes of SAIDI.

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. In 2016, KU completed a project that added two (2) 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 also replaced and rebuilt. From 2012 until the time this project was completed, the line experienced eleven (11) sustained events and contributed 8.6 minutes of SAIDI. Since the completion of these improvements, there have been six (6) sustained outages. Only one of those outages caused a SAIDI impact on a major event day of 0.1 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. In 2017, KU added a motor operated switch with auto reclosing scheme at the Radcliff station. From 2012 until the time the switch was installed, the line experienced ten (10) sustained events and contributed four (4) minutes of SAIDI for an average of 0.4 minutes per event. Since the completion of these improvements, there has only been one sustained outage in 2018 with a SAIDI impact of 0.1 minutes. The auto reclosing scheme prevented over 4,300 customers from experiencing the sustained outage.

4.2.4 Harlan Y to Evarts to Pocket

KU added a motor operated switch and implemented auto-reclosing scheme in 2017 at the Harlan 557 station on this line. From 2012 until the time this switch was installed, this circuit experienced nine (9) sustained events and accounted for 1.2 minutes of SAIDI. After this project was completed, this circuit experienced five (5) sustained events with a SAIDI impact of 0.8 minutes. The auto reclosing scheme prevented over 1,600 customers from experiencing the sustained outage during a major event day in 2020 and again in 2021 when a lightning arrestor failed.

4.2.5 Boyle County to Lancaster

In 2017, KU installed a breaker at Stanford. Prior to this project the circuit experienced two (2) sustained outages contributing 1.5 minutes of SAIDI. Since the project was completed there have been three (3) events as well; however, they total only 0.4 minutes of SAIDI.

4.2.6 Farley to Sweet Hollow 69 kV line

KU added a motor operated switch in 2017 at the Corbin Steel tap on this line. From 2012 until the time this switch was installed, this circuit experienced three (3) sustained events and accounted for 0.9 minutes of SAIDI for an average SAIDI of 0.3 minutes per event. After this project was completed, this circuit experienced two (2) sustained events with a SAIDI impact of 0.02 minutes. The motor operated switch at Corbin steel was used to sectionalize the line and restore most customers in less than five (5) minutes.

4.2.7 Millersburg (604) to Paris (634) 69 kV

KU added a motor operated switch and implemented auto-reclosing scheme in 2017 at the Paris tap on this line. From 2012 until the time this switch was installed, this circuit experienced seven (7) sustained events and accounted for 1.2 minutes of SAIDI for an average SAIDI of 0.2 minutes per event. After these projects were completed, this circuit experienced one (1) sustained events with no SAIDI impact. The auto-reclosing scheme at the Paris tap operated to sectionalize the line and restore the customers with no interruptions.

4.2.8 Hume Road to Winchester 69kV Line

KU added a motor operated switch and implemented auto-reclosing scheme in 2017 at the Haley tap on this line and added motors to two (2) switches at the Rockwell substation in 2018. From 2012 until the time these projects were implemented, this circuit experienced four (4) sustained events and accounted for 1.8 minutes of SAIDI. After these projects were completed, this circuit experienced three (3) sustained events with 0.13 min of SAIDI impact. The auto-reclosing scheme at the Haley tap and the motors at the Rockwell substation were used to sectionalize the line and minimize customers interruptions.

4.2.9 Lebanon to Taylor County 69kV Line

In 2017, KU added two motors to the existing switches with auto-reclosing scheme at Lebanon South tap and two (2) motors to the existing switches at Campbellsville Industrial tap in 2017. From 2012 until the time these motors were added, this circuit experienced seven (7) sustained events and accounted for 1.6 minutes of SAIDI. After these projects were completed in 2017, this circuit experienced four (4) sustained events with 0.14 min of SAIDI impact. The auto-reclosing scheme at the Lebanon South tap operated to sectionalize the line and restore the customers with no interruptions.

In 2021, KU added two switches with motors at the EKPC Lebanon tap. This line experienced two (2) sustained outages in 2021 with no SAIDI impact. The auto reclosing scheme prevented over 9,000 customers from experiencing the sustained outage during a major event day in 2021.

4.2.10 Spencer Road to Clark County 69kV Line

KU added motor operated switches and implemented auto-reclosing scheme in 2018 at the Mt Sterling tap on this line. From 2012 until the time this switch was installed, this circuit experienced two (2) sustained events and accounted for 0.5 minutes of SAIDI. After these projects were completed, this circuit experienced one (1) sustained events with no SAIDI impact. The auto-reclosing scheme at the Mt. Sterling tap operated to sectionalize the line and restore the customers with no interruptions.

4.2.11 Somerset EKPC to Russell Co EKPC 69 kV Interconnection

KU added two motors to existing switches and implemented auto-reclosing scheme in 2019 at the Waitsboro tap and added motors to two (2) switches at the Union Underwear tap in 2021. From 2012 until the time these projects were implemented, this circuit experienced one (1) sustained event and accounted for 0.35 minutes of SAIDI. After these projects were completed, this circuit experienced one (1) sustained events with no SAIDI impact. The auto-reclosing scheme at the Union Underwear tap and the motors at the Waitsboro tap were used to sectionalize the line and restore the customers with no interruptions.

4.2.12 Bardstown to Hodgenville EKPC 69 kV Interconnection

KU added a motor to the existing switch and implemented auto-reclosing scheme at the Barton tap in 2016 and added two motor operated switches at the Woodlawn substation in 2020. From 2012 until the time these projects were implemented, this circuit experienced four (4) sustained event and accounted for 1.1 minutes of SAIDI for an average SAIDI of 0.3 minutes per event. After these projects were completed, this circuit experienced one (1) sustained events with 0.04 min of SAIDI impact. The auto-reclosing scheme at the Barton tap and the motors at the Woodlawn substation were used to sectionalize the line and minimize customers interruptions.

4.2.13 East Frankfort to Tyrone 69kV

KU added motors to the existing switches at the Versailles West tap in 2021. From 2012 until the time these projects were implemented, this circuit experienced nine (9) sustained event and accounted for 0.9 minutes of SAIDI for an average SAIDI of 0.1 minutes per event. After these projects were completed, this circuit experienced one (1) sustained events with no SAIDI impact.

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 2021, the Companies also completed hazard tree patrols on over 920 transmission miles across the transmission system. These patrols identified roughly 525 ash trees and roughly 1,202 total hazard trees for removal. The Companies removed roughly 443 ash trees and roughly 252 total hazard trees in 2021. 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. TSIP Summary

As stated, the Companies continue to prioritize and invest in capital asset replacement and system maintenance strategies. The majority of the Companies' TSIP spend is attributed to System Integrity and they continue to utilize a flexible but prioritized approach that's focused on replacing aging infrastructure and improving efficiencies. The investments in Line Sectionalizing have consistently resulted in a more reliable system, with a reduction of 6.3 total minutes of SAIDI throughout the five years of the TSIP. O&M investments support this continued reliability, with cycled inspections for vegetation management and switch maintenance allowing for a more proactive approach to system maintenance. Through these replacements and programs, the Companies are able to continuously build upon their success of providing a safe, resilient, and reliable transmission system.