VOLUME 4.5

TRANSMISSION AND DISTRIBUTION ANALYSIS

KANSAS CITY POWER & LIGHT COMPANY (KCP&L)

INTEGRATED RESOURCE PLAN

4 CSR 240-22.045

APRIL 2018

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VOLUME 4.5: TRANSMISSION AND DISTRIBUTION ANALYSIS

HIGHLIGHTS

- KCP&L's transmission losses as a percent of peak load served are low relative to the SPP footprint as a whole.

- SPP identified one economic project in the KCP&L footprint through its 2017 ITP10 process - a two-ohm series reactor on the Northeast-Charlotte 161 kV line. The need date for this project was 1/1/2018.

- SPP identified one reliability project in the KCP&L footprint through its 2017 ITPNT process – adding redundant relaying on one of the transformers at the Stilwell substation. SPP identified the need date for this upgrade as 6/1/2021.

- A total of four transmission projects have been identified in the KCP&L territory, with need dates between 2018 and 2033.

PURPOSE: This rule specifies the minimum standards for the scope and level of detail required for transmission and distribution network analysis and reporting.

SECTION 1: ADEQUACY OF THE TRANSMISSION AND DISTRIBUTION NETWORKS

(1) The electric utility shall describe and document its consideration of the adequacy of the transmission and distribution networks in fulfilling the fundamental planning objective set out in 4 CSR 240-22.010. Each utility shall consider, at a minimum, improvements to the transmission and distribution networks that—

1.1 OPPORTUNITIES TO REDUCE TRANSMISSION POWER AND ENERGY LOSSES

(A) Reduce transmission power and energy losses. Opportunities to reduce transmission network losses are among the supply-side resources evaluated pursuant to 4 CSR 240-22.040(3). The utility shall assess the age, condition, and efficiency level of existing transmission and distribution facilities and shall analyze the feasibility and cost-effectiveness of transmission and distribution network loss-reduction measures. This provision shall not be construed to require a detailed line-by-line analysis of the transmission and distribution systems, but is intended to require the utility to identify and analyze opportunities for efficiency improvements in a manner that is consistent with the analysis of other supply-side resource options;

Electrical losses in a transmission line are primarily dependent on the specific characteristics of the line (conductor type, line length, etc.) and the amount of power flowing (I^2R) on the transmission line. KCP&L uses 161 kV transmission lines (approximately 1000 miles) for the majority of its load serving substations. Most of KCP&L’s existing 161 kV transmission lines use a single 1192 ACSR conductor per phase on H-frame wood structures. This design provides a normal line rating of 293 Mva and an emergency rating of 334 Mva for summer conditions. For increased transmission capability and lower line losses, KCP&L Transmission Engineering recommended using a line design with two, 1192 ACSR conductors per phase on H-frame wood or steel structures. This design provides a normal line rating of 586 Mva and an emergency rating of 668 Mva for summer conditions. Adding the additional conductor per phase reduces the line's electrical resistance by half and results in reduced transmission losses. Transmission Engineering estimated the cost to rebuild a single conductor per phase line to a two conductor per phase line at $950,000 per mile.

In order to "analyze the feasibility and cost-effectiveness of transmission network loss-reduction measures", KCP&L Transmission Planning staff analyzed the costs and loss reductions associated with rebuilding five of KCP&L's most heavily loaded 161kV transmission lines. This analysis involved calculating new impedances values for the five transmission lines converted from single 1192 conductor to bundled 1192 conductors and performing a loadflow analysis to determine the level of loss reduction for the rebuilt lines. Results of this analysis for 2018 summer peak conditions are shown in Table 1 below.

Table 1: Cost Analysis for 161kV Transmission Line Loss Reduction

TRANSMISSION LINES		2018 SP	LINE IMPEDENCE				
FROM	TO	Flow (MW)	R	X	B	Line Mile	
			1192 ACSR CONDUCTOR				
WGARDNR5	BNSF 5	254.5	0.0008	0.0071	0.0041	2.61	
MOONLT 5	MOONLT 5	245.4	0.00114	0.01019	0.00551	3.43	
MARTCTY5	STHTOWN5	234.5	0.00339	0.0223	0.0117	7.76	
Stilwell-Antioch	MOONLT 5	182.5	0.0011	0.0092	0.0049	3.2	
STILWEL5	HICKMAN5	167.8	0.0046	0.0387	0.0205	13.54	
TOTAL KCP&L LOSSES AT PEAK LOAD							66.4
			1192 BUNDLED CONDUCTOR				
WGARDNR5	BNSF 5	280.9	0.0004	0.00355	0.00548	2.61	
MOONLT 5	BNSF 5	271.8	0.00057	0.00509	0.0072	3.43	
MARTCTY5	STHTOWN5	287	0.0017	0.01115	0.0163	7.76	
STHTOWN5	FOREST 5	250	0.00055	0.0046	0.00672	3.2	
STILWEL5	HICKMAN5	216.3	0.0023	0.01935	0.02843	13.54	
TOTAL KCP&L LOSSES AT PEAK LOAD							64.3
MW LOSS REDUCTION using 1192 BD conductor in KCP&L							2.1
TOTAL LINE MILES							30.5
TOTAL COST TO RECONDUCTOR/REBUILD AT $950,000 PER MILE							$29,013,000
AVERAGE COST OF LOSS REDUCTION						$/kW	$ 13,816

The average cost of loss reduction for these five transmission lines is $13,816/kw. This is approximately six times the average $/kw construction cost of Iatan 2. Clearly transmission loss reduction is not cost effective for KCP&L when compared to the cost of construction for new supply side resources. This is mainly due to the fact that KCP&L already has a relatively low loss transmission system.

The KCP&L transmission system is a relatively low loss network due to good line design, concentration of load, and the distribution of its generation resources throughout its service territory. As shown in Table 2, KCP&L’s projected transmission loss as a percent of peak load served for 2018 summer peak load conditions is only 1.7%. The comparative value for the rest of the Southwest Power Pool (SPP) is 2.6%.

Table 2: SPP 2018 Transmission Losses by Area

Area	Load MW	Loss MW	% Loss
652	3,991.6	191.7	4.8%
640	3,644.6	158.9	4.4%
515	690.6	29.2	4.2%
525	1,666.2	47.2	2.8%
544	1,122.3	31.3	2.8%
524	6,664.9	174.7	2.6%
534	1,205.0	29.4	2.4%
526	6,472.2	156.8	2.4%
520	10,346.3	246.2	2.4%
536	5,866.2	131.5	2.2%
540	2,013.1	38.8	1.9%
531	437.2	8.3	1.9%
523	1,125.8	18.8	1.7%
KCP&L	4,012.9	66.4	1.7%
645	2,739.1	44.9	1.6%
546	804.2	11.9	1.5%
650	754.6	10.3	1.4%
545	308.8	2.7	0.9%
542	529.0	2.2	0.4%
659	240.4	0.8	0.3%
527	337.3	0.7	0.2%
SPP	54,972.2	1,402.9	2.6%

1.1.1 DISTRIBUTION SYSTEM OVERVIEW

The various KCP&L planning groups (Supply, Transmission, and Distribution) assimilates a broad set of engineering inputs to determine how the company will invest in improving the respective systems to meet ongoing load growth, system reliability, operational efficiency and asset optimization needs. The Distribution Planning group analyzes data, identifies patterns, develops electrical models representative of the KCP&L distribution system, and performs studies to understand and prioritize system improvement needs.

The KCP&L Missouri tariff area consists of three general types of areas: a predominantly developed urban core; suburban areas in the territory fringes and;

one rural area. The inner urban core can be characterized by high utilization of its distribution assets and its aging infrastructure. Reliability risk in this area is addressed by installing replacement or contingency infrastructure and infrastructure inspections as noted in Section 1.1.2.4 (Conditions). The distribution system, over many decades, has been built by adding only enough capacity to serve immediate load requirements. These types of problems have been categorized as condition or contingency, and specific recognizable projects like the Troost Substation and the Twelfth Street Duct Bank Reconstruction are good examples of this type of investment.

In contrast, are the suburban areas of the KCP&L system, where new development of open land requires the build-out of the distribution system. The highest load growth is seen on the fringe, demanding investments to serve new emerging electrical loads – largely a capacity issue. Circuits must be tied together more effectively to allow for contingency switching and disperse the load across a larger number of circuits, all the while expanding substation breaker positions for these new circuits. Many investments like this have been made in recent years, especially around Line Creek, Shoal Creek, and BNSF Substations.

The rural areas have the most widespread infrastructure components and have the fewest or most limited emergency ties, where any load manipulation can cause large disturbances to customers' voltage. Distribution Planning carefully examines these systems to assure customer voltages are within tolerance, a process which demands high-quality mapping and device load data. With so many widespread components, acquiring data has become one of the greatest challenges in these areas.

The Distribution Planning group is tasked with elevating the highest priority and highest-risk projects to a point where investments are made earlier than those with lower priorities and risk profiles. Many years of constant review have provided the group with a robust set of criteria within which these problems are evaluated, and even today process improvements are being made to further analyze how well to build out the distribution system to assure cost-effectiveness.

Furthermore, the Long-Term Planning component handled by Distribution Planning assures strategic long-term investments are made. Solutions are selected based upon how well they fit into an area-plan and not just the cost-effectiveness for the immediate need. Between the robust planning criteria and the strategic long-term vision, Distribution Planning will continue to construct the distribution system capable of serving tomorrow's needs by making appropriate investments when they are needed.

In the inner-urban core of Kansas City, the long-term vision involves installing replacement substation assets in new locations to strategically phase-out deteriorated underground components, improve reliability, and provide additional area capacity. Components nearing the end of their useful life can then be abandoned, removed, or rebuilt, and the company will have an upgraded distribution system better suited to reliably serve the inner-urban core of Kansas City well into the future. The Charlotte Substation and associated duct bank projects have been budgeted in the five-year plan and will continue to have components critical to the long term strategy over the next twenty years.

On the suburban fringe, Distribution Planning plots out growth patterns to identify substation sites well ahead of the need. On the Northern edge of the Metro Area, several substation sites have already been purchased in anticipation of future load growth. Distribution Planning constantly reviews the build-out of the distribution system on the suburban fringe as development in Kansas City continues this march North, South, and East of the current Metro Area.

The rural areas of the service territory are envisioned to one day have entirely remotely-received load and condition data – a completely automated system. Today, load information is difficult to obtain, due to low resolution watt-var charts or manual field load checks during peak periods. Strategic and timely decisions can better be made with abundant characteristic data for the components being studied. Efforts are underway to systematically bring all rural components up to metro-area data acquisition standards.

It is the goal of Distribution Planning to assure that every investment optimizes capital spend and balances risk, meets current and future needs, and is built strategically when and where they are needed. Many tools and a great deal of information is processed and analyzed to develop these strategic plans.

1.1.2 ANNUAL SCOPE OF WORK

Throughout each year, Distribution Planning prepares a number of system studies to determine weaknesses or risks to reliability and to assess the overall adequacy of our distribution system. The majority of the work focuses on increasing reliability and prioritizing work based upon cost, scope, impact, and effectiveness. This work is centered around four (4) specific areas which include capacity, contingency, voltage and condition. The table below illustrates the various deliverables associated with each focus area:

Table 3: Distribution Planning - Annual Scope of Work

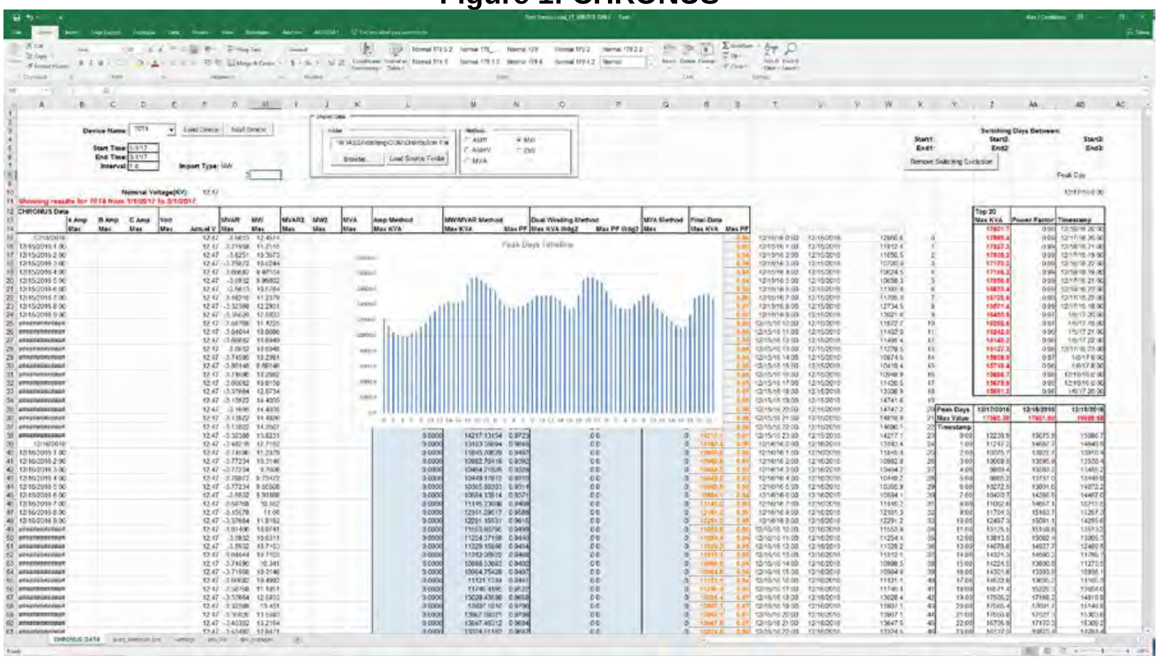
Category	Study Name	Deliverable
Capacity	Load Preservation 5 Yr. System Expansion – Load Device Weather Adjustment 20 Year Forecast Circuit Rating Study	Black Start Plan Budgetary Recommendations Distribution Load Book Forecasted Substation Loads Circuit Rating utilized for Operational Guidance
Contingency	5 Yr. System Expansion – contingency N-1 Circuit Contingency Study N-1 Transformer Contingency Study	Budgetary Recommendations Circuit Contingency Plan Transformer Contingency Plan
Voltage & Losses	Phase Balancing Voltage Drop Studies System Efficiency Studies Capacitor Studies Voltage Regulation Studies	Load-Swap Recommendations DVC Operational Guidance System Loss Studies Capacitor Installations Substation Tap Settings
Condition	Worst Performing Circuits Circuit Review Short Circuit Studies Other Reviews	Budgetary Recommendations Budgetary Recommendations Customer-Required Special Studies

To complete this identified scope of work, KCP&L Planning Engineers utilize a variety of tools that make use of the device loads and system schematics as input. There are several tools currently in use at KCP&L to collect and process this information.

PI/Network Manager

During the summer of 2016, the new Energy Management System (EMS) was placed in-service. With this product, KCP&L also utilizes the CHRONUS data archive tool, which now contains device loads and other historical system characteristics. Once all system components are merged into the new system, CHRONUS will be the primary archive for engineers to find and extract load and voltage history. The figure below provides a snapshot of the data extracted from CHRONUS.

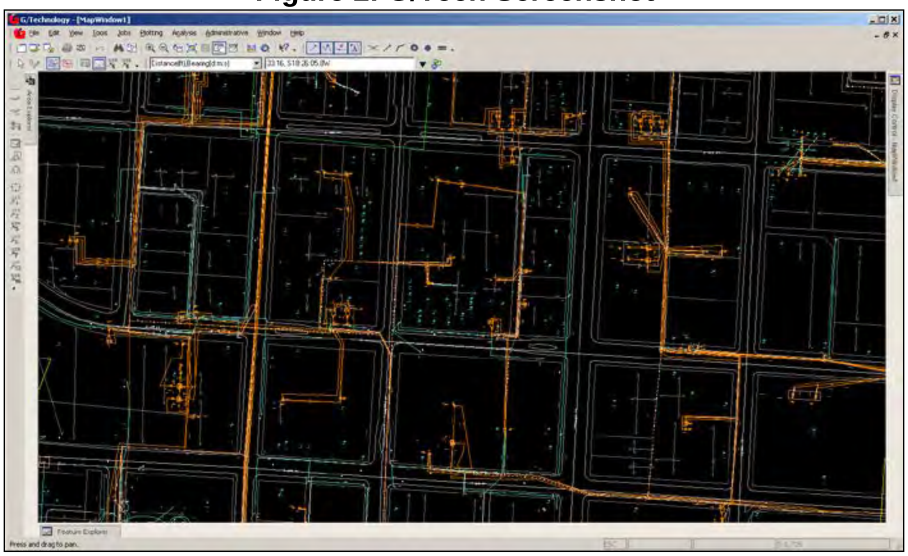
Figure 1: CHRONUS



GTechnology

The software mapping tool used by Distribution Planning engineers is called GTech. The KCP&L distribution system G.I.S. database is viewed and extracted from GTech, where engineers acquire model data for use in Synergi. Device characteristics and connectivity drive load-flow models in use by Distribution Planners. The figure below provides a snapshot of G/Tech.

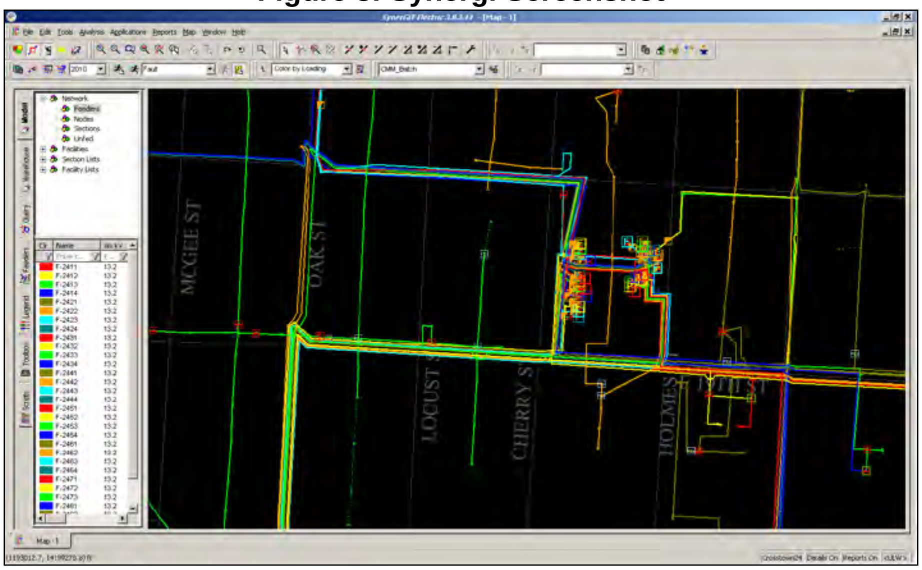
Figure 2: G/Tech Screenshot



Synergi

A multipurpose tool primarily used by engineers to analyze load flow characteristics of distribution feeders. Distribution Planning is also responsible for providing fault current information to customer's electrical contractors when performing arc-flash studies, a process which requires the use of Synergi. The figure below provides a snapshot of the Syngergi software program.

Figure 3: Synergi Screenshot



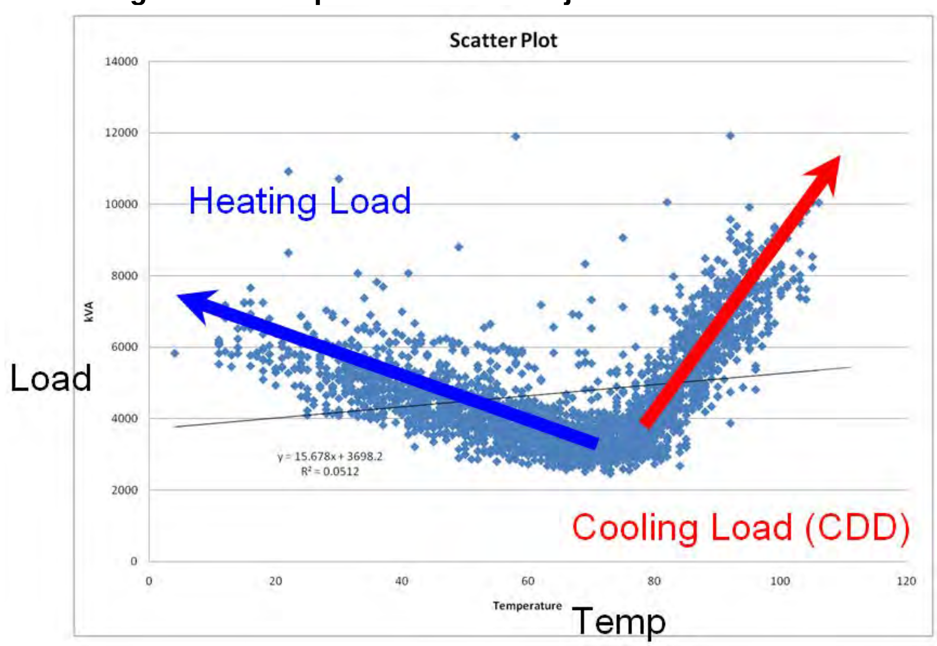
1.1.2.1 Capacity Planning

Device loads, such as substation transformer and distribution circuit loads are collected annually from a number of remote-sensing sources and are weather-adjusted to determine the effects of temperature (heating & cooling). This load data is compared to previous years' loads and device maximum loading to determine how the load is changing over time and if any component is overloaded and in need of an upgrade. These types of problems are given a higher priority than others to assure continued reliability.

1.1.2.1.1 Device Weather Adjustment

The whole system improvement process begins with Device Weather Adjustment. There are a number of ways engineering monitors and records the loads experienced across the distribution system, and however this is done, load data is gathered and tabulated. The daily peak demand is then compared with the daily high temperature (for Winter, the daily low temperature), and a comparison is made using an excel scatter-plot with a linear-regression best-fit line.

Figure 4: Example of Weather-Adjustment Scatter Plot



Distribution Planning cleanses the data using filters to assure outlying data points (abnormal behaviors) are omitted from the study. What results is a linear equation, where the variable ‘x’ refers to the temperature. For ‘x’, Distribution Planning inserts 100 degrees Fahrenheit, the chosen planning temperature at KCP&L. This then yields a weather-adjusted peak demand, which is utilized throughout the rest of the planning process.

Figure 5: Example Scatter Plot after data filtered to show collating loads

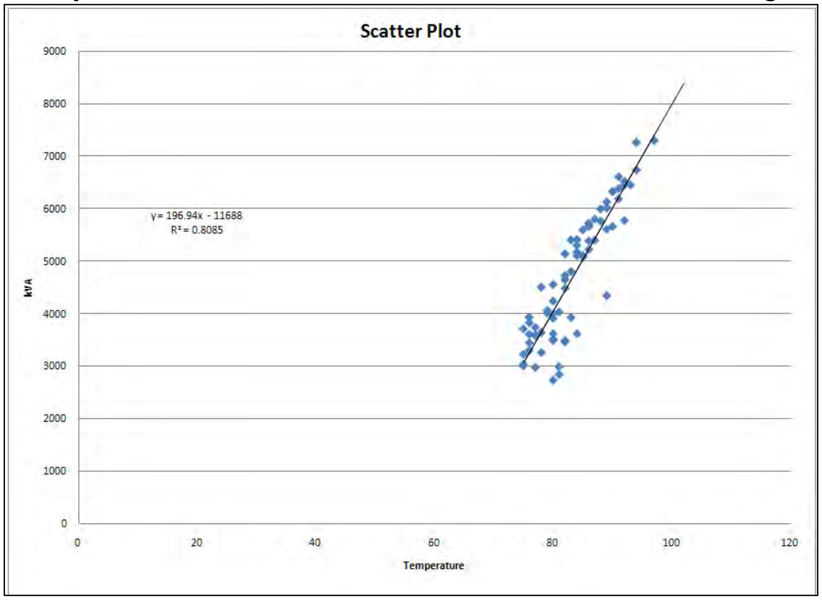
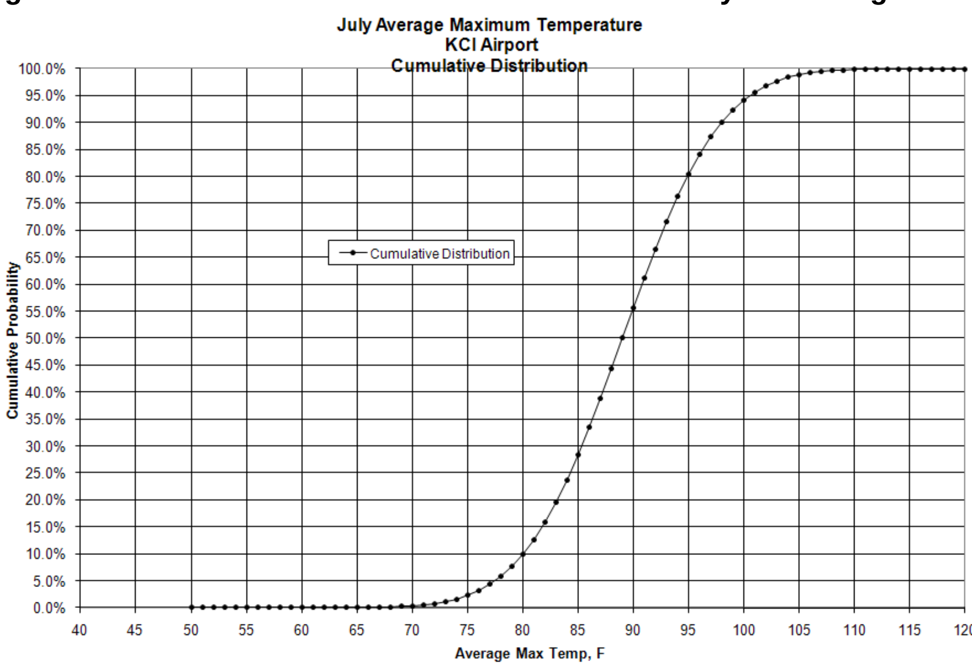


Figure 6: Cumulative Distribution Plot - 95% certainty at 100 degrees F



For load driven higher by increasing temperatures, the chart above shows at what temperature the Kansas City Area tops out. Temperatures above 105 degrees Fahrenheit are almost nonexistent historically and statistically. For Kansas City, the 95% mark (5% of the time temperature runs hotter) is 100 degrees F. For

Distribution Planning, taking 5% risk means planning to a weather-adjusted temperature of 100 degrees F.

One hundred degrees Fahrenheit planning temperature was chosen for several reasons. First, Corporate Planning uses 100 degrees for their studies, and Distribution Planning felt it appropriate to match their criteria for distribution expansion projects. Second, 100 degrees represents a five percent risk, meaning there is a five percent chance in any given year the temperature will exceed 100 degrees on at least one day, sending system loads beyond designed capacity. Third, 100 degrees best-matched the previous design criteria in terms of system improvement dollars needed in a given year.

1.1.2.1.2 Circuit Rating Study

Armed with weather-adjusted loads, Distribution Planning can produce ratings for each circuit. Again, this study is done in several different ways depending on the configuration and style of the distribution components being looked at. The most complex of these studies deals with underground feeder cables within duct bank, which de-rate each other by mutual heating. Distribution Planning uses weather-adjusted loads to determine capacity 'choke-points' in order to rate the circuit. These ratings are provided to operations to set alarms, and become an integral part of the N-1 Contingency Study. These ratings are also compared with native device loads to determine where normal-load capacity expansions are needed, leading to budget recommendations.

Figure 7: Screenshot from Cable De-rating Program

Description	Duct Bank from M.H. 2312 East to M.H. 2313	
Rows	6	***# of Positions***
Columns	2	10
Ambient	22	
Earth Rho	90	

Position	*Circuit*	*load factor*	*running load*	*vertical*	*horiz.*	*Nom Ckt Voltage*	*Duct Type*	*Cable Type*
1	1561	0.67	204	77.8	5.6	13	4.5"-Fibre	1-400 KCM-3C PILC
2	7472	0.67	35	77.8	12.9	13	4.5"-Fibre	1-400 KCM-3C PILC
3	1574	0.67	201	70.5	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
4	1511	0.67	123	70.5	12.9	13	4.5"-Fibre	1-750 KCM-3C PILC
5	1743	0.67	185	63.2	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
7	1567	0.67	109	55.9	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
9	7432	0.67	228	48.6	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
10	1522	0.67	178	48.6	12.9	13	4.5"-Fibre	1-750 KCM-3C PILC
11	1523	0.67	180	41.3	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
12	1512	0.67	195	41.3	12.9	13	4.5"-Fibre	1-750 KCM-3C PILC

Circuit	*Load (A)*	*Oper. Temp.*	*Norm. Amp.*	*Norm. MVA*	*Emerg. Amp.*	*Emerg. MVA*
1561	204	50.6	380	8.68	428	9.78
7472	35	37.8	369	8.44	418	9.55
1574	201	45.1	522	11.93	575	13.15
1511	123	40.6	520	11.88	575	13.15
1743	185	44.0	522	11.94	575	13.15
1567	109	40.3	522	11.93	575	13.15
7432	228	45.7	536	12.26	575	13.15
1522	178	42.4	533	12.19	575	13.15
1523	180	41.0	544	12.44	575	13.15
1512	195	41.7	546	12.47	575	13.15

1.1.2.1.3 <u>Spatial Electric Load Forecast Study (Electric Vehicle Study)</u>

KCP&L with the help of Integral Analytics, Inc. (IA) conducted a rigorous electric vehicle impact study and a long-range spatial load forecast study. The study details long-range substation load growth due to increases in employment, population, and estimates the future adoption of electric vehicles at different penetration levels for the entire KCP&L service territory. The study intent was to help distribution planners identify future capacity constrained areas due to future electric vehicle load additions and to proactively plan for distribution expansion work before system loading became an issue.

Electric vehicles present a significantly large end use load to the distribution system. To study the potential distribution impact of vehicle electrification, one must understand the customer key drivers of adoption. Therefore, IA designed a discrete choice survey and recruited 113 KCP&L residential customers randomly to participate in a discrete choice survey online. The survey results were processed and unique electric vehicle adoption and charging behavior segments were developed. The segmentation was applied to the KCP&L customer base with demographic information pulled from the Experian database. A probability of adoption score was assigned to each KCP&L customer based on the segmentation analysis. The scoring identified the customers most likely to purchase electric vehicles. Finally, the customers were mapped geographically to locate potential electric vehicle customer clusters at different penetration levels in the KCP&L service territory.

The worst case scenario of 100 percent of new vehicles sold in the KCP&L service territory are electric vehicles show, on average, the load will increase by 2,500 kilowatts per substation over the next 20 years. Therefore, residential electric vehicle charging at the local or neighborhood levels will resemble normal load growth. KCP&L annually reviews distribution feeder capabilities and implements necessary upgrades to meet the electricity requirements. KCP&L does not anticipate substation loading issues. However, KCP&L does anticipate localized loading issues at the distribution line transformer level providing service to a cluster of customer who all adopt EV. Localized distribution line transformer loading can be easily resolved by upgrading the size of the transformer and/or the line size feeding the transformers.

The electric vehicle impact study provides distribution planning a 20 year forecast of future loading by substation for different electric vehicle penetration scenarios. The scenario based planning methodology has allowed distribution planning to understand the anticipated impact of electric vehicles in the KCP&L service territory at the substation level. The electric vehicle study did highlight a few potential loading issues but overall the impact of electric vehicles on the distribution networks will to be very minimal over the next 20 years. Appendix 4.5.F contains a complete copy of the “Spatial Electric Load Forecast Study”.

1.1.2.2 Contingency Planning

Contingency Planning is similar to Capacity Planning in its view of loads compared to device capacity, but deals in an N-1 contingency setting. KCP&L designs its system to withstand a failure of any one component at a given time. It is the responsibility of Distribution Planning Engineers to determine system weaknesses which do not comply with this and to make the necessary changes to allow emergency switching to restore power without overloading backup devices. These issues have a secondary priority in the budgetary process.

1.1.2.2.1 N-1 Contingency

The annual contingency study will provide the earliest indication of system improvement needs. It is more likely wire upgrades will be needed in the case of feeder or transformer loss, rather than there being simply too much native load on a single feeder or substation transformer. For Distribution Planning, the N-1 Contingency Study is a very systematic and complex process due to the magnitude of the individual distribution system circuit components. Synergi is the primary software tool in use to determine the load flow across a circuit. Distribution Planners break apart circuits into segments of load, and establish switching orders for restoration in the case of a feeder or substation transformer loss. Synergi, using G.I.S. models exported from GTech and weather-adjusted load data, actually determines how that load is spread across the circuit by allocating the load based on the by-phase connected KVA on each circuit.

Three very complex inputs into one N-1 Contingency Study using a highly-technical software program yields effective results determining where system improvement is needed. By using the model to rearrange the configuration of circuitry using Synergi, Distribution Planning can detect where mapping errors exist, where low voltage can be problematic, and where wire sizes can limit how the distribution system is operated. Contingency Planning is an intensely complex process taking significant engineering time in order to determine system weaknesses for a given planning year. The study is completed every year for every distribution feeder and for the loss of every substation transformer.

These weaknesses, once identified, are further analyzed to determine the impact to system reliability and are ranked against each other correspondingly. Ultimately, this ranking, energy efficiency impacts, reliability and customer impact risks, and the project cost determine whether a system improvement is constructed or not. Distribution Planning therefore must not only identify the weakness, but provide some budgetary estimation and project description. It also becomes the responsibility of Distribution Planning to thoroughly communicate why a project exists throughout the company, until it becomes part of the approved budget and is handed-off to a design engineer for sponsorship.

1.1.2.3 Distribution Voltage

At the customer-end of any given line, distribution voltage must be maintained within specific tolerances. It is the responsibility of Distribution Planning to assure system-level issues do not adversely affect the voltage received by KCP&L customers. To do this, G.I.S. models are used in a load-flow program called Synergi to simulate voltage levels in the field. In addition to supplying adequate voltage levels to our customers, we also strive to maintain an efficient low-loss distribution system. Several examples of this are the annual load balancing efforts and capacitor studies to optimize voltage levels and reduce system losses.

1.1.2.3.1 Loss Studies

Another method of analyzing overall system efficiency is through the performance of system loss studies. These are done periodically and the information gathered is used by Planning Engineering as well as in rate case filings. The most recent system loss study was performed by Siemens in October, 2014. A complete copy of this study, “Kansas City Power & Light Electric System Loss Analysis”, can be found in Appendix 4.5.G.

1.1.2.3.2 KCP&L Green Circuits Analysis

Another example of KCP&L's efforts to improve overall circuit efficiency and reduce system losses was a study commissioned by KCP&L and completed by EPRI (Electric Power Research Institute). This study analyzed various loss reduction options such as phase balancing, capacitor controls, re-conductoring, and/or voltage optimization. The information gathered by this study has been used by Planning Engineering to optimize their approach to circuit construction, configuration and operation. A complete copy of this study, "KCP&L Green Circuits Analysis Study", can be found in Appendix 4.5.H.

1.1.2.3.3 Distribution Transformer Efficiency Analysis

Currently, KCP&L purchases transformers based on the Total Ownership Cost (TOC), which includes the transformer purchase price as well as the cost of the no-load and load-losses associated with each transformer, capitalized over a 30 year expected transformer life. As of 2010, all KCP&L transformers were purchased utilizing the Department of Energy (DOE) transformer efficiency standards, which has enabled KCP&L to optimize the TOC of all transformers over a 30 year period.

1.1.2.4 Condition

Another important focus area for Distribution Planning Engineering deals with component conditions and their effect on reliability as it relates to capacity, contingency, voltage and overall system efficiency. Ongoing strategic planning to maintain reliability must account for device degradation over time, and planning engineers look for cost-effective replacement or maintenance opportunities where they coincide with capacity expansion plans. By working with the Asset Management group to determine the best course of action, these replacements in some cases are combined into Distribution Planning's capacity expansion projects – an increase in project scope from the normal course of action. System expansion to replace degraded system components can be a more cost-effective solution than the "run-to-failure" strategy.

1.1.2.4.1 URD Cable Replacement Programs

Currently, there are two cable replacement programs in existence at KCP&L: 1) Proactive Cable Replacement, and 2) Reactive Cable Replacement.

The Proactive Cable Replacement/Rehabilitation program targets Underground Residential Distribution (URD) primary cable loops and laterals that are shown to have elevated risk of failure based on engineering analysis. Cable failure data is collected on an ongoing basis and compiled to show area results and trends. The analysis of this data helps prioritize the areas that are selected for our proactive programs. KCP&L currently employs two different programs for URD system rejuvenation, which are the (i) Cable Assessment, and (ii) Cable Injection programs, respectively.

The Reactive Cable Replacement program addresses service reliability issues associated with URD primary cable. KCP&L collects condition history and performs lifecycle analysis on failed cables. When an individual cable section has experienced two faults in its life, it is designated for mandatory replacement. For cables failing for the first time, an engineering analysis encompassing outage frequency history, the age of cable, and the history of other faulted cables on the immediate system is made. The analysis is used to evaluate the potential risk of a future cable failure which may be indicative of a need to replace the cable. In addition, there are field conditions that make cable replacement the best option for cables after a single failure.

1.1.2.4.2 Cable Assessment Program

In the Cable Assessment Program, the insulation properties of individual cable segments are evaluated using a partial discharge test which evaluates the cable's integrity. Based on the results of these tests, a decision is made on which cable segments to replace.

1.1.2.4.3 Cable Injection Program

The Cable Injection program rejuvenates the existing cable's insulation through a process widely-used in the industry that injects a silicon fluid into the strands of a conductor. The fluid flows into the conductor shield and insulation, modifying the insulation's chemistry and extending cable life. Injection contractors provide a minimum warranty of 20 years, with the option to upgrade to as much as 40 years with better injection fluids. Cable injection companies are used by KCP&L to perform these activities.

1.1.2.4.4 Worst Performing Circuit Analysis

The High Outage Count Customer Program, also known as the "Worst Performing Circuits" Program, is a circuit-based program addressing service reliability issues associated with customers experiencing abnormally high outage counts. KCP&L identifies high outage count customers, investigates their outage events, and develops solutions to improve their circuit reliability. The Company uses the definition found in the MPSC reliability rule, 4 CSR 240-23.010 (6) to identify the top five percent (5%) worst performing circuits and to prioritize work needed to improve their reliability.

Predictive reliability analysis forecasts along with mathematical equivalents of each component in the system are obtained to aid in understanding root causes.

This analysis also considers the historical circuit performance and, with the use of linear regression, forecasts the future reliability performance. The top ranked five percent (5%) high outage count customer circuits are analyzed annually to ensure reliability improvements are being achieved.

1.1.2.4.5 Pole Replacement and Reinforcement Program

The Distribution Pole Replacement/Reinforcement Program addresses reliability issues associated with the condition of distribution poles. KCP&L annually conducts a ground-line inspection of the system to determine if there is a need to replace or reinforce distribution poles. The evaluation includes an examination for indications of decay and/or fungi at or below ground level, hollowness, and shell rot. When a pole is identified for replacement or reinforcement, the Company uses an independent contractor who is an expert in pole evaluation, maintenance, and repair, to prioritize and coordinate pole maintenance or replacement. The work is prioritized based on greatest risk to safety and impact to customer reliability. Annual pole rejection rate is calculated to be 0.025% per 1,000 pole inspections.

1.1.2.4.6 Lateral Improvement Program

The Lateral Improvement Program addresses system-wide distribution reliability performance. KCP&L conducts analysis to identify unfavorable reliability metrics. The systematic approach used determines root causes of irregular system component performances—such as pole or cross-arm failure, cutouts, arrester malfunction, grounding issues, undetected equipment vandalism and/or other undetected damage, among others. Detailed condition assessments and risk-modeling are used to formulate solutions concentrated on specific reliability issues. Projects are prioritized based on the magnitude and impact of customer outage.

1.1.2.4.7 Proactive Retirement of 50 MVA Substation Transformers

The Asset Management group has also proactively undertaken a study to asses KCP&L's fleet of 50 MVA dual-secondary winding transformers, determine their risk of failure, and develop a retirement/replacement program. The condition of each transformer is primarily based upon dissolved gas analysis taken from annual transformer oil sampling. KCP&L utilizes a transformer analysis package that categorizes each transformer as a category 1, 2, 3, or 4, with category 4 being the worst condition. This program reduces the overall operational risk associated with transformers that are identified as being at a higher risk for failure.

1.2 ASSESMENT OF INTERCONNECTING NEW FACILITIES

(B) Interconnect new generation facilities. The utility shall assess the need to construct transmission facilities to interconnect any new generation pursuant to 4 CSR 240-22.040(3) and shall reflect those transmission facilities in the cost benefit analyses of the resource options;

Any KCP&L generation resource addition that would impact transmission level (>60 kV) flows would have to proceed through the Southwest Power Pool (SPP) Generation Interconnection process before it could be interconnected to the transmission system. The Interconnection process is detailed in SPP's Federal Energy Regulatory Commission (FERC) approved transmission tariff provisions, which allows customers detailed transmission studies and interconnection estimates for connecting to and using KCP&L's transmission system. The resource addition would also have to be included in the SPP Aggregate Facility Study process to obtain firm transmission service for delivery of generation to load.

1.3 <u>ASSESSMENT OF TRANSMISSION UPGRADES FOR POWER PURCHASES</u>

(C) Facilitate power purchases or sales. The utility shall assess the transmission upgrades needed to purchase or sell pursuant to 4 CSR 240-22.040(3). An estimate of the portion of costs of these upgrades that are allocated to the utility shall be reflected in the analysis of preliminary supply-side candidate resource options; and

KCP&L is member of the Southwest Power Pool (SPP) a Regional Transmission Organization (RTO), mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. As a member of SPP, KCP&L participates in the regional transmission expansion plan processes of the RTO, including requesting firm transmission service through the Aggregate Facility Study (AFS) process, which evaluates the transmission upgrades necessary for delivery of power purchases.

1.4 <u>ASSESSMENT OF TRANSMISSION OR DISTRIBUTION IMPROVEMENTS WITH RESPECT TO COST EFFECTIVENESS OR DSM OR SUPPLY-SIDE RESOURCES</u>

(D) Incorporate advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources. The utility shall assess transmission and distribution improvements that may become available during the planning horizon that facilitate or expand the availability and cost effectiveness of demand-side resources or supply-side resources. The costs and capabilities of these advanced transmission and distribution technologies shall be reflected in the analyses of each resource option.

1.4.1 CAPACITOR AUTOMATION EFFORTS

KCP&L, an industry leader in Distribution Automation (DA), began its automation initiatives in the early 1990's by deploying several hundred automated capacitors in the metropolitan area using the CellNet fixed network communication system also used for the automated meter reading system (AMR) at that time.

Since the early 1990's, KCP&L has worked with Sensus (formerly Telemetric) to develop automated capacitor controls with integrated radios for use throughout the KCP&L service territory. This technology uses radios that leverage the commercial cell coverage infrastructure while also providing secure communications and technology applications for KCP&L users. This added technology is particularly cost effective and successful in rural and other areas where other communication infrastructure is not cost effective.

AT&T decommissioned it's 2G public cellular network at the beginning of 2016. KCP&L has upgraded all critical distribution automation communications to 3G or 4G generations. Less critical equipment, including fixed capacitor banks, are targeted to be upgraded to 4G by mid- to late-2019.

The business case for automated capacitors includes:

- Upgrade existing capacitors with controls with new technical features
    - Voltage Override
    - Neutral Sensing
    - Limiting number of switching operations per day
    - Ability to change setpoints remotely
    - Ability to obtain power quality data for improved customer service
- Optimizing utilization of these existing capacitor banks
- Enhancing safety for KCP&L workers
    - Five minute time delay in control for a close after an open
    - One minute timer for close after faceplate control operation
- Reduced O&M

    - Limiting number of capacitor patrols due to real time data
    - Limiting number of customer voltage complaints
    - Extending life of existing capacitor switches

- Improved Distribution and Transmission Power Factor

    - Enhance System Stability
    - Enhance system volt/VAr response
    - Increase system efficiency
- Enabling component for Dynamic Voltage Control (DVC)

1.4.2 DYNAMIC VOLTAGE CONTROL

KCP&L also has been a pioneer in demand reduction from voltage reduction during peak summer loading. KCP&L already had a progressive capacitor automation system in place. This became the foundation for another successful KCP&L distribution automation project called Dynamic Voltage Control (DVC).

The business case components for this project were as follows:

MW Demand reduction from controlled voltage reduction

Better substation voltage regulation

Improved process for load tap changer setpoints

Integration of substation load tap changer and distribution capacitors by settings and practical application versus complex feedback loops

Remote control of load tap changer for planned switching

Provide Remote setpoint changes for authorized users

Release MVAr in support of transmission and distribution system

The project involved replacing electromechanical and non-communicating load tap changer controls with electronic load tap changer controls that use DNP (Distributed Network Protocol) messaging. This intelligent electronic device (IED) streams DNP messaging into a remote terminal unit (RTU). KCP&L developed

EMS screens and applications to support remote setpoint changes as well as the ability to see the actual settings values.

KCP&L installed this system throughout the legacy KCP&L metro area from 2005-2008. KCP&L dispatchers now use the system to successfully accomplish all the desired tasks shown above.

SECTION 2: AVOIDED TRANSMISSION AND DISTRIBUTION COST

(2) Avoided Transmission and Distribution Cost. The utility shall develop, describe, and document an avoided transmission capacity cost and an avoided distribution capacity cost. The avoided transmission and distribution capacity costs are components of the avoided demand cost pursuant to 4 CSR 240-22.050(5)(A).

The KCP&L transmission projects included in the SPP regional planning processes for reliability improvement or economic benefits would not be impacted by the implementation of DSM programs. Therefore, the only avoided cost for transmission facilities are the transmission equipment additions associated with distribution facility expansions.

2.1 IMPACT OF DSM ON DISTRIBUTION EXPANSION

As in the 2012 IRP submittal, KCP&L made assumptions regarding planned system expansion projects in areas that are designated as "growth areas" versus areas designated as "established areas". Again, targeting was focused on capital projects associated within established areas since targeted DSM programs were unlikely to be able to delay the need to expand substations on the fringe of metro-area growth due to the fact that these areas contained significant "green space" with large areas that remain undeveloped.

Distribution Planning's annual review of 20 year load projections revealed the fact that loads for these "established areas" continue to flatten and more commonly, decline, which has eliminated the need for expansion projects in these areas. It seems reasonable that as load growth has fallen off in the established areas, that efficiencies gained by replacing older heating/cooling units, lighting, and other older appliances, would begin to significantly impact peak loads for these areas. In the 2012 IRP submittal, the Gladstone, Claycomo, and Chouteau substations were identified as substations located in established areas where a system expansion project might be needed at some point in the future, making these a good candidate for targeted DSM programs. However, a review of the most recent 20 year projections actually identify these substations to be in modest to significant load decline through year 2034, with total substation loads dropping from as little as 2% at Gladstone to as much as 17% at Choteau substation.

Currently, KCP&L has not identified any specific capital projects located within any established areas that can be specifically targeted for DSM programs. Areas that have been identified as established areas either have sufficient capacity available to absorb the limited growth, or are in load decline. These areas will continue to be monitored by Distribution Planning to determine if future opportunities for targeted DSM might become available. Should economic conditions improve, and/or significant redevelopment occurs in these established areas, opportunities to target DSM programs to delay or eliminate the cost to expand capacities for these areas may again exist.

SECTION 3: ANALYSIS OF TRANSMISSION NETWORK PERTAINENT TO A RESOURCE ACQUISITION STRATEGY

(3) Transmission Analysis. The utility shall compile information and perform analyses of the transmission networks pertinent to the selection of a resource acquisition strategy. The utility and the Regional Transmission Organization (RTO) to which it belongs both participate in the process for planning transmission upgrades.

3.1 TRANSMISSION ASSESSMENTS

(A) The utility shall provide, and describe and document, its—

3.1.1 TRANSMISSION ASSESSMENT FOR CONGESTION UPGRADES

1. Assessment of the cost and timing of transmission upgrades to reduce congestion and/or losses, to interconnect generation, to facilitate power purchases and sales, and to otherwise maintain a viable transmission network;

In 2009, the SPP Board of Directors approved a new Integrated Transmission Planning (ITP) process that will determine the transmission needed to maintain electric reliability and provide near- and long-term economic benefits to the SPP RTO region.

The ITP is an iterative three-year process that includes a 20-Year, 10-Year, and Near-Term Assessment. The 20-Year Assessment evaluates the high voltage transmission (345 kV +) needs over a 20 year study period to meet load growth and other future scenarios and potential developments. The second iteration of the 20-Year Assessment (ITP20), conducted in 2012-2013, included an examination of high voltage transmission needs while taking into account reliability, economic, and public policy needs. Five distinct futures were considered to account for possible variations in system conditions over the assessment's 20-year horizon, including: (1) business as usual; (2) additional wind assuming a 20%

federal Renewable Electricity Standard; (3) additional wind as in item (2) plus approximately 10 GW of additional wind generation to be exported outside of SPP; (4) combined policy, which approximates the effects of additional investment in Demand Side Management and Smart Grid technology, additional wind as in item (2), and a carbon constraint; and (5) a joint SPP/MISO future. The SPP Board of Directors voted to approve the ITP20 Report on July 30, 2013. The cost of the plan was estimated at $560 million through the construction of 405 miles of 345 kV lines, 31 miles of 161 kV lines, and six various 345 kV step-down transformers. KCP&L did receive one transmission project as a result of the ITP20 study – an increase of the 345/161 kV transformer size to 650/715 MVA at Nashua. Although an ITP20 study was scheduled to be completed in 2016, SPP requested and was granted a waiver from the FERC to instead complete another 10-Year Assessment due to the quickly changing climate in the industry.

The 10-Year Assessment is a value-based planning approach that analyzes the transmission system over a 10-year horizon. Economic and reliability analyses are utilized to identify 100 kV and above solutions for issues identified on the 69 kV and above system, as well as issues identified by the 20-Year Assessment appropriate for the 10-Year Assessment. The most recent iteration of the 10-Year Assessment (ITP10) was conducted in 2015-2016, with the final report issued in January 2017. Three distinct futures were considered to account for possible variations in system conditions: (1) a reference case, which assumed that no major changes to policies were in place; (2) a regional Clean Power Plan solution, which assumed that the Environmental Protection Agency's Clean Power Plan (CPP) would be implemented at the regional level by meeting emission targets within the SPP footprint and each of its neighboring regions, and also included an increase in large-scale solar development and minimal distributed solar development over the reference case; and (3) a state-level CPP solution, which assumed that the CPP would be implemented at the state level by meeting emissions targets within each state and contained the same solar development as the regional CPP future. The recommended 2017 ITP10 portfolio was estimated at $201 million engineering and construction cost and includes projects needed to meet potential reliability and economic requirements. KCP&L received one transmission project as a result of the ITP10 study – a two-ohm series reactor on the Northeast-Charlotte 161 kV line. The need date for this project was 1/1/2018.

The Near-Term Assessment of the ITP evaluates transmission system reliability in the near-term planning horizon. The Assessment will identify potential problems using NERC Reliability Standards, SPP Criteria, and local planning criteria. Mitigation plans are developed to meet regional reliability needs and identify necessary reliability upgrades for all voltage levels for approval and construction. The most recent iteration of the Near-Term Assessment (ITPNT) was conducted in 2016-2017, with the final report issued in April 2017. The 2015 ITPNT included three scenario models, Scenarios 0, 5, and SPP Balancing Authority (BA), built across multiple years and seasons to account for various system conditions across the near-term horizon. The Scenario 0 and 5 models allow only resources with firm transmission service to be dispatched with the preferred order submitted by SPP members, while the BA model allows for resources without firm transmission service to be dispatched and is intended to mimic the SPP Integrated Marketplace by dispatching around constraints on the system. SPP performed reliability analyses identifying potential bulk power system problems. These findings were presented to Transmission Owners and stakeholders to solicit transmission solutions. Also considered were transmission options from other SPP studies, such as the Aggregate Study and Generation Interconnection processes. From the resulting list of potential solutions, staff identified the best regional solutions for mitigation of potential reliability violations and presented them for member and stakeholder review at SPP's planning summit. Through this process, SPP developed a final list of 69 kV and above solutions necessary to ensure the reliability in the SPP region in the near-term. Engineering and Construction (E&C) cost estimates for new and modified reliability projects identified in the 2017 ITPNT totaled $60.524 million. Additionally, previously identified projects worth $37.04 million were withdrawn. In the 2017 ITPNT assessment, KCP&L received a project to add redundant relaying at its Stilwell substation. SPP identified the need date for this upgrade as 6/1/2021.

After several cycles of the ITP process, the SPP Strategic Planning Committee and Market and Operations Policy Committee directed a group of stakeholders to seek ways to improve upon the current process. SPP is currently transitioning to the updated process, which is intended to make the SPP transmission planning process more responsive to the effects of the continued growth of SPP's transmission system, changes in the SPP markets, as well as the challenges and opportunities presented by changing federal and state energy and environmental regulations, and NERC compliance requirements. As opposed to having three distinct planning assessments covering different time horizons, there will be one process covering both near and long-term views, with a single study released annually. The first such study is expected to be completed in 2019.

3.1.2 TRANSMISSION ASSESSMENT FOR ADVANCE TECHNOLOGIES

2. Assessment of transmission upgrades to incorporate advanced technologies;

KCP&L currently makes use of three advanced technologies in its transmission system: Hybrid Structure Design, Solid Dielectric Cables, and Fiber Optic Shield Wire.

KCP&L uses a hybrid steel and wood H-Frame structures for both single and double circuit applications. Using steel poles, provides easier installation due to their lower weights compared to other materials, and the use of wood X-bracing provides a cost effective option to conventional steel bracing and allows us to use established stock materials. Steel replacement arms and bracing for both 161 and 345 kV H-Frame structures are used to reduce construction and maintenance costs. Each assembly is rated for helicopter installation weight not to exceed 800 pounds per lift. This layout allows the use of smaller helicopters for both energized and normal maintenance change out work.

KCP&L is using solid dielectric cables at 161 kV for specific applications at power plants where limited space made conventional bus or overhead circuit installations impractical or impossible. The cable design is based on 230 kV cable specifications with insulation levels for 161 kV operation.

KCP&L currently uses optical ground wire (OPGW) for most or all of new shield wire installations. This gives not only superior lightning performance, due to the lower resistance of the OPGW compared to conventional galvanized steel strand shield wires, but also provides a high capacity path for internal communications and system protection functions. The standard OPGW options provide either 48 or 72 single mode fibers per shield wire.

3.1.3 AVOIDED TRANSMISSION COST ESTIMATE

3. Estimate of avoided transmission costs; 22.045 Transmission and Distribution Analysis,

The KCP&L transmission projects included in the SPP regional planning processes for reliability improvement or economic benefits would not be impacted by the implementation of DSM programs. Therefore, the only avoided cost for transmission facilities are the transmission equipment additions associated with distribution facility expansions.

3.1.4 REGIONAL TRANSMISSION UPGRADE ESTIMATE

4. Estimate of the portion and amount of costs of proposed regional transmission upgrades that would be allocated to the utility, and if such costs may differ due to plans for the construction of facilities by an affiliate of the utility instead of the utility itself, then an estimate, by upgrade, of this cost difference;

Table 4 below shows the SPP projected annual transmission revenue requirement allocated to KCP&L for regional transmission upgrades.

Table 4: SPP Projected ATRR Allocated to KCP&L

Year	Projected Region-Wide Revenue Requirement	Allocated to KCP&L Zone	Allocation to KCP&L Native System Load
2017	$ 552,831,741	$ 44,806,872	$ 39,483,816
2018	$ 578,285,052	$ 46,560,360	$ 41,028,989
2019	$ 648,207,059	$ 51,793,302	$ 45,640,257
2020	$ 678,665,615	$ 54,017,397	$ 47,600,130
2021	$ 671,387,843	$ 53,398,967	$ 47,055,170
2022	$ 638,735,336	$ 50,735,875	$ 44,708,453
2023	$ 566,252,002	$ 44,807,108	$ 39,484,024
2024	$ 548,971,884	$ 43,435,851	$ 38,275,672
2025	$ 531,691,766	$ 42,064,593	$ 37,067,320
2026	$ 514,411,648	$ 40,693,336	$ 35,858,968

The region-wide revenue requirement includes amounts for projects owned by Transource Missouri. Transource Missouri is a wholly-owned subsidiary of Transource Energy, LLC, which is a joint venture between transmission holding company subsidiaries of Great Plains Energy Incorporated (“GXP”), the holding company for KCP&L and GMO, and American Electric Power (“AEP”). GXP owns 13.5 percent of Transource Energy and AEP owns the other 86.5 percent. Table 5 below shows the 2018 region-wide revenue requirement for the Transource Missouri projects. The primary difference in revenue requirements for these Transource Missouri projects compared to what the revenue requirements would have been had these projects been owned by KCP&L or GMO is that Transource Missouri requested and received FERC approval for Construction Work in Progress (“CWIP”) in ratebase treatment for these projects. The CWIP in ratebase treatment results in increased revenue requirements in rates prior to the in-service date of the projects but decreased revenue requirements in rates after in-service. Both of the Transource Missouri projects were in service by the end of 2016. It should be noted, however, that per the Commission’s Report and Order in File No. EA-2013-0098, KCP&L and GMO make adjustments in rate cases to account for the revenue requirement differences related to CWIP in ratebase and certain other differences.

3.1.5 REVENUE CREDITS ESTIMATE

5. Estimate of any revenue credits the utility will receive in the future for previously built or planned regional transmission upgrades; and

Table 5 below shows the region-wide 2018 revenue requirement for the SPP-directed projects owned by KCP&L.

Table 5: Region-Wide Revenue Requirements for SPP Projects Owned by KCP&L

KCP&L SPP-Directed Projects	2018 Region-Wide Revenue Requirement
Projects with NTCs issued prior to June 19, 2010	
Tomahawk-Bendix Reconductor	$ 23,992
West Gardner Autotransformer	$ 117,003
Stilwell-Antioch Reconductor	$ 51,428
South Waverly Capacity Bank	$ 15,629
Antioch-Oxford Reconductor	$ 34,568
Antioch-Oxford Reconductor Switches	$ -
Reconductor Craig-College -161kV Line	$ 10,700
Craig Sub 161 kV Capacitor Bank	$ 40,074
Mayview -Line Terminal Equipment to 600amps	$ -
Total	$ 293,394
Projects with NTCs issued after June 19, 2010	
Loma Vista E.-Winchester Jct -161kV	$ 4,915
W. Gardner Line Terminals	$ 38,719
Swissvale-Stilwell Tap at W. Gardner	$ 277,916
	$ 321,550
Projects with Need Date after October 1, 2015	
Northeast-Charlotte-Crosstown -161kV Reactor	$ 30,525
Stilwell Relaying	$ 9,712
Iatan Stranger 345kV Voltage Conversion	$ 246,322
	$ 286,559
Total KCP&L SPP-Directed Projects	$ 901,503

Source: SPP Revenue Requirements & Rates (RRR) file for rates effective 1/1/2018 (as posted 1/15/2018)

3.1.6 TIMING OF NEEDED RESOURCES ESTIMATE

6. Estimate of the timing of needed transmission and distribution resources and any transmission resources being planned by the RTO primarily for economic reasons that may impact the alternative resource plans of the utility.

The 2015 ITP10 identified one economic project in the KCP&L service territory – a voltage conversion of the current Iatan – Stranger Creek 161 kV line to 345 kV. The need date for this project was identified as 1/1/2019. The 2017 ITP10 also identified one economic project in KCP&L – a two-ohm series reactor on the Northeast-Charlotte 161 kV line.

These projects were identified within the SPP transmission planning process to reduce transmission congestion and provide regional production cost savings. They will have minimal impact on KCP&L alternative resource plans.

3.2 USE OF RTO TRANSMISSION EXPANSION PLAN

(B) The utility may use the RTO transmission expansion plan in its consideration of the factors set out in subsection (3)(A) if all of the following conditions are satisfied:

See response to Section 3.1.1 above for description of SPP RTO transmission expansion planning processes.

3.2.1 UTILITY PARTICIPATION IN RTO TRANSMISSION PLAN

1. The utility actively participates in the development of the RTO transmission plan;

KCP&L actively participates in the development of SPP transmission expansion plans through a number of related activities. These include participation in the Model Development Working Group (MDWG), the Transmission Working Group (TWG), and regional transmission expansion workshops

Participation in the MDWG involves reviewing and updating the transmission planning models used for regional transmission expansion analysis. This includes adding KCP&L transmission projects into the planning models and providing a substation level load forecast for the seasonal and future years planning models. The expected generation dispatch required to meet KCP&L load requirements is also included in these models. These models form the basis for the reliability analysis needed to identify future transmission projects to maintain reliable service and reduce transmission congestion.

The Transmission Working Group (TWG) is responsible for planning criteria to evaluate transmission additions, seasonal Available Transfer Capability (ATC) calculations, seasonal flowgate ratings, oversight of coordinated planning efforts, and oversight of transmission contingency evaluations. The TWG works with individual transmission owners on issues of coordinated planning and North American Electric Reliability Corporation (NERC) and SPP compliance. The TWG coordinates the calculation of the ATC for commerce maintaining regional reliability, while ensuring study procedures and criteria are updated to meet the regional needs of SPP, in cooperation with governing regulatory entities. The TWG is responsible for publication of seasonal and future reliability assessment studies on the transmission system of the SPP region. The TWG works closely with the Economic Studies Working Group (ESWG) to develop the scope documents used to direct the analysis and studies performed for the ITP process.

SPP hosts three to four ITP workshops annually to get stakeholder input to the transmission planning process and provide analysis results for stakeholder review. The workshops allow SPP stakeholders to provide input on assumptions for economic analysis and review identified needs and proposed solutions selected by SPP. KCP&L proposes projects through SPP's FERC Order No. 1000 process, reviews selected transmission projects in its area and coordinates with SPP regarding details within its area that may affect proposed solutions. In other instances KCP&L offers an operating guide to mitigate a transmission problem and avoid new transmission construction.

3.2.2 <u>ANNUAL REVIEW OF RTO EXPANSION PLANS</u>

2. The utility reviews the RTO transmission overall expansion plans each year to assess whether the RTO transmission expansion plans, in the judgment of the utility decision makers, are in the interests of the utility's Missouri customers;

KCP&L reviews transmission projects in its area and coordinates with SPP regarding details within its area that may affect proposed solutions or requests restudy for projects that it believes are not required. In other instances KCP&L offers an operating guide to mitigate a transmission problem and avoid or delay new transmission construction.

3.2.3 ANNUAL REVIEW OF SERVICE TERRITORY EXPANSION PLAN

3. The utility reviews the portion of RTO transmission expansion plans each year within its service territory to assess whether the RTO transmission expansion plans pertaining to projects that are partially- or fully-driven by economic considerations (i.e., projects that are not solely or primarily based on reliability considerations), in the judgment of the utility decision-makers, are in the interests of the utility's Missouri customers;

KCP&L reviews transmission plans and projects within its service territory that develop through the SPP RTO transmission expansion plan. Many are zonal projects providing additional obligations to serve or meet specific planning and bulk electric reliability criteria.

For region-wide project sets identified through the SPP Integrated Transmission Planning process, projects meet a wide range of needs including reduced production costs, reduced congestion, reduced system losses and base reliability needs. For example, in the case of the voltage conversion of the Iatan- Stranger Creek 161kV line to 345kV, the project is expected to reduce congestion near the Kansas City area and relieves limitations on the ability to dispatch KCP&L's Iatan 2 generating unit.

3.2.4 DOCUMENTATION AND DESCRIPTION OF ANNUAL REVIEW OF RTO OVERALL AND UTILITY-SPECIFIC EXPANSION PLANS

4. The utility documents and describes its review and assessment of the RTO overall and utility-specific transmission expansion plans; and

KCP&L reviews transmission projects in its area and coordinates with SPP regarding details within its area that may affect proposed solutions or requests restudy for projects that it believes are not required. KCP&L planning personnel participate throughout the year within the planning process providing insight and review of the transmission plans. In some instances KCP&L may be able to offer an operating guide to mitigate a transmission problem and avoid or delay new transmission construction. Also, KCP&L personnel participate in the overall approval of RTO expansion plans through the SPP approval process within the Markets and Operation Policy Committee and Members Committee.

3.2.5 AFFILIATE BUILD TRANSMISSION PROJECT DISCUSSION

5. If any affiliate of the utility intends to build transmission within the utility's service territory where the project(s) are partially- or fully-driven by economic considerations, then the utility shall explain why such affiliate built transmission is in the best interest of the utility's Missouri customers and describe and document the analysis performed by the utility to determine whether such affiliate-built transmission is in the interest of the utility's Missouri customers.

On April 4, 2012 Great Plains Energy ("GXP"), the holding company for both KCP&L and GMO, and American Electric Power ("AEP") announced the formation of a company to build and invest in transmission infrastructure. The new company, Transource EnergySM LLC ("Transource"), will pursue competitive transmission projects in the SPP region, the MISO and PJM regions, and potentially other regions in the future. GXP owns 13.5 percent of Transource through its newly-formed subsidiary, GPE Transmission Holding Company, LLC ("GPETHCO"). AEP owns the other 86.5 percent of Transource through its subsidiary, AEP Transmission Holding Company, LLC ("AEPTHC").

At this point, it is GXP's intent to pursue, develop, construct, and own through GPETHCO's interest in Transource – rather than through KCP&L and/or GMO – any future regional and inter-regional transmission projects subject to regional cost allocation. While it is premature to determine the specific impact on the regionally allocated costs resulting from constructing projects within Transource, it is anticipated that the partnership between GXP and AEP will provide for a financially-strong, cost-competitive, and technically-proficient transmission development entity. The scale, execution experience, and engineering expertise that Transource expects to be able to bring to the projects should provide benefits to customers through lower construction costs, better access to capital, and operational efficiencies.

3.3 RTO EXPANSION PLAN INFORMATION

(C) The utility shall provide copies of the RTO expansion plans, its assessment of the plans, and any supplemental information developed by the utility to fulfill the requirements in subsection (3)(B) of this rule.

The following SPP regional transmission planning reports are provided as attachments to this report.

2013 SPP ITP20_Assessment_Report_Final.pdf (Appendix 4.5.A)

2017 SPP ITP10 Report Final.pdf (Appendix 4.5.B)

2017 SPP ITPNT Assessment Report.pdf (Appendix 4.5.C)

2018 SPP Transmission Expansion Plan Report .pdf (Appendix 4.5.D)
2018 SPP Transmission Expansion Plan Project List.xls (Appendix 4.5.E)

The ITP20, ITP10, ITPNT reports are described in Section 3.1.1 above. The 2018 SPP Transmission Expansion Plan (STEP) Report and Project List summarize 2017 activities that impact future development of the SPP transmission grid. Six distinct areas of transmission planning are discussed in this report: Transmission Services, Generation Interconnection, Integrated Transmission Planning, High Priority Studies, Sponsored Upgrades, and Interregional Coordination.

3.4 TRANSMISSION UPGRADES REPORT

(D) The utility shall provide a report for consideration in 4 CSR 240-22.040(3) that identifies the physical transmission upgrades needed to interconnect generation, facilitate power purchases and sales, and otherwise maintain a viable transmission network, including:

3.4.1 TRANSMISSION UPGRADES REPORT – PHYSICAL INTERCONNECTION WITHIN RTO

1. A list of the transmission upgrades needed to physically interconnect a generation source within the RTO footprint;

It is not possible to provide a specific list of transmission upgrades needed to physically interconnect a generation resource within the SPP footprint. Any generation interconnection request within the SPP must proceed through the generation interconnection process as defined by the SPP transmission tariff. That process will examine the specific location proposed for generator interconnection and develop the necessary transmission upgrades needed at that location.

3.4.2 TRANSMISSION UPGRADES REPORT – DELIVERABILITY ENHANCEMENT WITHIN RTO

2. A list of the transmission upgrades needed to enhance deliverability from a point of delivery within the RTO including requirements for firm transmission service from the point of delivery to the utility's load and requirements for financial transmission rights from a point of delivery within the RTO to the utility's load;

In the SPP, requests for firm transmission service are processed through the Aggregate Facility Study (AFS) process. The AFS process is performed two times per year by collectively analyzing specific transmission service requests, including those associated with generation interconnection requests, across the entire SPP footprint. These service reservations are modeled based on control area to control area transfers. The transmission system is assessed with these potential service requests and, where needed, transmission improvements are identified that would enable the service to occur without standard or criteria violations. All transmission customers are allocated cost responsibility for portions of the various upgrades needed to deliver all of the transmission service requests. Transmission customers may adjust their conditions following the posting of the preliminary results if their initial conditions were not met; otherwise, the request will be considered withdrawn. This is an iterative process until all conditions are met. The remaining transmission customers with service requests in the process agree to the projects needed to deliver the remaining transmission service and share the resulting upgrade costs. Those remaining upgrade projects are included in the next SPP transmission expansion plan process.

Because of the iterative nature of the Aggregate Facility Study process it is not possible to identify specific transmission upgrades needed to deliver energy from a resource in the RTO footprint to KCP&L until the process for a specific transmission service request has been completed.

3.4.3 TRANSMISSION UPGRADES REPORT – PHYSICAL INTERCONNECTION OUTSIDE RTO

3. A list of transmission upgrades needed to physically interconnect a generation source located outside the RTO footprint;

It is not possible to develop a list of specific upgrades needed to interconnect a generation resource located outside the SPP without actually making a generation interconnection request at a specific location.

3.4.4 TRANSMISSION UPGRADES REPORT – DELIVERABILITY ENHANCEMENT OUTSIDE RTO

4. A list of the transmission upgrades needed to enhance deliverability from a generator located outside the RTO including requirements for firm transmission service to a point of delivery within the RTO footprint and

requirements for financial transmission rights to a point of delivery within the RTO footprint;

It is not possible to develop a list of specific upgrades needed to deliver capacity and energy from a generation resource located outside the SPP without actually making a generation interconnection request and an associated transmission service request at a specific location.

3.4.5 TRANSMISSION UPGRADES REPORT – ESTIMATE OF TOTAL COST

5. The estimated total cost of each transmission upgrade; and

A list of KCP&L transmission projects included in the 2018 SPP Transmission Expansion Plan (STEP) is shown below in

Table 6: KCP&L Transmission Upgrades 2018 SPP STEP

Transmission Project	Cost Estimate	Project Type	Need Date
Increase rating of Nashua transformer to 650/715 MVA.	$12,600,000	ITP	1/1/2033
Install any terminal upgrades required at Iatan to convert existing 18.2-mile 161 kV line from Iatan to Stranger Creek to 345 kV operation.	$ 3,263,000	Economic	1/1/2019
Install new 2-ohm line reactor at Northeast substation on the 161 kV line from Northeast to Charlotte to Crosstown	$ 500,000	Economic	1/1/2018
Install relaying at Stilwell (STWL 11) 345/161/13.8 kV transformer Ckt 11 to address Category P5 Event violations.	$ 147,500	Regional Reliability	6/1/2018

Total estimated construction cost for these transmission upgrades is $16,510,500.

3.4.6 TRANSMISSION UPGRADES REPORT – COST ESTIMATES

6. The estimated fraction of the total cost and amount of each transmission upgrade allocated to the utility.

A list of KCP&L transmission projects included in the 2018 SPP STEP and the portion of their estimated cost allocated to KCP&L is shown below in Table 7.

Table 7: Transmission Upgrade Cost Allocated to KCP&L

Transmission Project	Cost Estimate	% Allocated to KCP&L	KCP&L $
Increase rating of Nashua transformer to 650/715 MVA.	$12,600,000	69.2%	$ 8,724,328
Install any terminal upgrades required at Iatan to convert existing 18.2-mile 161 kV line from Iatan to Stranger Creek to 345 kV operation.	$ 3,263,000	6.8%	$ 221,558
Install new 2-ohm line reactor at Northeast substation on the 161 kV line from Northeast to Charlotte to Crosstown	$ 500,000	69.2%	$ 346,204
Install relaying at Stilwell (STWL 11) 345/161/13.8 kV transformer Ckt 11 to address Category P5 Event violations.	$ 147,500	6.8%	$ 10,015

SECTION 4: ADVANCED TECHNOLOGY ANALYSIS

(4) Analysis Required for Transmission and Distribution Network Investments to Incorporate Advanced Technologies.

4.1 TRANSMISSION UPGRADES FOR ADVANCED TRANSMISSION TECHNOLOGIES

(A) The utility shall develop, and describe and document, plans for transmission upgrades to incorporate advanced transmission technologies as necessary to optimize the investment in the advanced technologies for transmission facilities owned by the utility. The utility may use the RTO transmission expansion plan in its consideration of advanced transmission technologies if all of the conditions in paragraphs (3)(B)1. Through (3)(B)3. are satisfied.

KCP&L will use advanced technologies such as Hybrid Structure Design, Solid Dielectric Cables, and Fiber Optic Shield Wire where applicable in transmission upgrades included in the SPP regional transmission expansion plan.

4.2 DISTRIBUTION UPGRADES FOR ADVANCED DISTRIBUTION TECHNOLOGIES

(B) The utility shall develop, and describe and document, plans for distribution network upgrades as necessary to optimize its investment in advanced distribution technologies.

KCP&L has not established a program to invest in distribution network upgrades to optimize its investments in advanced distribution technologies. Instead, KCP&L deploys advanced distribution technologies selectively to the network where they are the most economical alternative to maintain the desired level of operational performance, reliability, and power quality.

The previous discussion, in Section 1.4 of this document, discusses how KCP&L plans distribution network upgrades, many of which incorporate the deployment of the previously established advanced grid technologies described in Section 4.6.2.1.

4.3 OPTIMIZATION OF INVESTMENT IN ADVANCED TRANSMISSION AND DISTRIBUTION TECHNOLOGIES

(C) The utility shall describe and document its optimization of investment in advanced transmission and distribution technologies based on an analysis of—

4.3.1 OPTIMIZATION OF INVESTMENT – TOTAL COSTS AND BENEFITS

1. ***Total costs and benefits, including:***

4.3.1.1 Distribution Analysis

KCP&L has not yet performed a comprehensive analysis to optimize investments in advanced distribution technologies.

In 2009, KCP&L management pursued a DOE SmartGrid Demonstration Grant. KCP&L was awarded this grant in 2009 and executed a contract with the DOE for the demonstration in September 2010. The DOE project ended in 2015 with decommissioning of unselected technologies continuing into 2016. The geographical components of the project were within Kansas City, MO.

Upon completion of the SmartGrid Demonstration Project KCP&L submitted a final Report to the DOE in 2016. Due to the breadth of the project, the report is over 900 pages. Due to the length of the report, it has not been included with this filing. The final report is available to the public on-line at:

https://www.smartgrid.gov/recovery_act/program_impacts/regional_demonstration_technology_performance_reports

Although many of the advanced technologies in the SmartGrid Demonstration Project were deemed "not ready" for widespread deployment, several have been or are being implemented by KCP&L. These include:

- Advanced Metering Infrastructure (AMI)
- Modernized Operations Management system (OMS)
- Distribution SCADA-Lite (SCADA-like monitoring and control within the OMS)
- Meter Data Management system (MDM)
- Real-time integration of AMI-MDM-OMS. Facilitates outage (and restoration) reporting from customer meters to the OMS. Also facilitates real-time, on-demand meter reads.
- Electric Vehicle Charging infrastructure
- Enterprise Service Bus infrastructure (implemented the Oracle Service Bus architecture)
- Demand Response (DR) programs (although not tied to a Distributed Energy Resource Management system like the demonstration project)
- Roof top solar (although not GMO-owned like the demonstration project)
- Fault Location Isolation and Service Restoration (FLISR)
- Capacitor Automation

The SmartGrid project team was disbanded after the project. Each of the above technologies/systems are dispersed to responsible GMO departments. After completion of the project, these advanced technologies are not managed under a single “SmartGrid” umbrella. Each of the technologies are assessed for cost/benefit vs. alternative investments on a case-by-case basis. Outside of the enterprise-level back-office systems (AMI, OMS, MDM, ESB), a pilot for proof of concept is usually performed before wide-scale deployment. (Pilots are prudent in cases where the current project utilizes technology different from the Demonstration Project). Electric Vehicle Charging was implemented in a forward thinking, future-ready approach.

4.3.2 OPTIMIZATION OF INVESTMENT – COST OF ADVANCED GRID INVESTMENTS

A. Costs of the advanced grid investments;

4.3.2.1 Distribution

Refer to comments in Section 4.3.1.1

4.3.3 OPTIMIZATION OF INVESTMENT – COST OF NON-ADVANCED GRID INVESTMENTS

B. Costs of the non-advanced grid investments;

4.3.3.1 Distribution

Refer to comments in Section 4.3.1.1

4.3.4 OPTIMIZATION OF INVESTMENT – REDUCTION OF RESOURCE COSTS

C. Reduced resource costs through enhanced demand response resources and enhanced integration of customer-owned generation resources; and

4.3.4.1 Distribution

Refer to comments in Section 4.3.1.1

4.3.5 OPTIMIZATION OF INVESTMENT – REDUCTION OF SUPPLY-SIDE COSTS

D. Reduced supply-side production costs;

4.3.5.1 Distribution

Refer to comments in Section 4.3.1.1

4.4 COST EFFECTIVENESS OF INVESTMENT IN ADVANCED TRANSMISSION AND DISTRIBUTION TECHNOLOGIES

2. Cost effectiveness, including

4.4.1 COST EFFECTIVENESS – INCREMENTAL COSTS ADVANCED GRID TECHNOLOGIES VS NON-ADVANCED GRID TECHNOLOGIES

A. The monetary values of all incremental costs of the energy resources and delivery system based on advanced grid technologies relative to the costs of the energy resources and delivery system based on non-advanced grid technologies;

4.4.1.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.2 COST EFFECTIVENESS – INCREMENTAL BENEFITS ADVANCED GRID TECHNOLOGIES VS NON-ADVANCED GRID TECHNOLOGIES

B. The monetary values of all incremental benefits of the energy resources and delivery system based on advanced grid technologies relative to the costs and benefits of the energy resources and delivery system based on non-advanced grid technologies; and

4.4.2.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.3 <u>OPTIMIZATION OF INVESTMENT – NON-MONETARY FACTORS</u>

C. Additional non-monetary factors considered by the utility;

4.4.3.1 <u>Distribution</u>

Refer to comments in Section 4.3.1.1

4.4.4 <u>OPTIMIZATION OF INVESTMENT – SOCIETAL BENEFIT</u>

4.4.4.1 <u>3. Societal benefit, including:</u>

4.4.4.2 <u>Societal Benefit – Consumer Choice</u>

A. More consumer power choices;

4.4.4.2.1 <u>Distribution</u>

Refer to comments in Section 4.3.1.1

4.4.4.3 <u>Societal Benefit – Existing Resource Improvement</u>

B. Improved utilization of existing resources;

4.4.4.3.1 <u>Distribution</u>

4.4.4.4 <u>Refer to comments in Section 4.3.1.1</u>

4.4.4.5 <u>Societal Benefit – Price Signal Cost Reduction</u>

C. Opportunity to reduce cost in response to price signals;

4.4.4.5.1 <u>Distribution</u>

Refer to comments in Section 4.3.1.1

4.4.4.6 <u>Societal Benefit –</u>

D. Opportunity to reduce environmental impact in response to environmental signals; Environmental Impact

4.4.4.6.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.5 OPTIMIZATION OF INVESTMENT – OTHER UTILITY-IDENTIFIED FACTORS

4. Any other factors identified by the utility; and

4.4.5.1.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.6 OPTIMIZATION OF INVESTMENT –OTHER NON-UTILITY IDENTIFIED FACTORS

5. Any other factors identified in the special contemporary issues process pursuant to 4 CSR 240-22.080(4) or the stakeholder group process pursuant to 4 CSR 240-22.080(5).

4.4.6.1 Distribution

Refer to comments in Section 4.3.1.1

4.5 NON-ADVANCED TRANSMISSION AND DISTRIBUTION INCLUSION

(D) Before the utility includes non-advanced transmission and distribution grid technologies in its triennial compliance filing or annual update filing, the utility shall—

4.5.1 NON-ADVANCED TRANSMISSION AND DISTRIBUTION REQUIRED ANALYSIS

1. Conduct an analysis which demonstrates that investment in each non-advanced transmission and distribution upgrade is more beneficial to consumers than an investment in the equivalent upgrade incorporating advanced grid technologies. The utility may rely on a generic analysis as long as it verifies its applicability; and

4.5.1.1 Distribution

KCP&L is not proposing any new non-advanced distribution grid technologies or programs in this triennial IRP compliance filing.

KCP&L understands that prior to including new non-advanced distribution grid technologies in future IRP filings, KCP&L will conduct, describe, and document an analysis which demonstrates that investment in each non-advanced distribution upgrade is more beneficial to consumers than an investment in the equivalent upgrade incorporating advanced grid technologies. KCP&L further understands that we may present a generic analysis as long as we verify its applicability.

4.5.2 NON-ADVANCED TRANSMISSION AND DISTRIBUTION ANALYSIS DOCUMENTATION

2. Describe and document the analysis.

4.5.2.1 Distribution

Refer to comments in Section 4.5.1.1

4.6 ADVANCED TRANSMISSION AND DISTRIBUTION REQUIRED COST-BENEFIT ANALYSIS

(E) The utility shall develop, describe, and document the utility's cost benefit analysis and implementation of advanced grid technologies to include:

4.6.1.1 Distribution

KCP&L is not proposing any new advanced distribution grid technologies or programs in this triennial IRP compliance filing.

KCP&L understands that prior to including new advanced distribution grid technology in future IRP filings, KCP&L will develop, describe, and document the cost benefit analysis for implementation of the advanced grid technology.

4.6.2 ADVANCED GRID TECHNOLOGIES UTILITY'S EFFORTS DESCRIPTION

1. A description of the utility's efforts at incorporating advanced grid technologies into its transmission and distribution networks;

4.6.2.1 Distribution

Historical Advanced Grid Technology Deployments

The distribution grid in place at KCP&L today is substantially "smart" having benefited from decades of power engineering expertise. The existing systems already execute a variety of sophisticated system operations and protection functions. In addition, it should be noted that what is now termed "smart grid" has been under development by KCP&L and the industry for many years. Much of the automation has been accomplished through incremental applications of technology. The following sections describe many of the advanced distribution technologies that have and are currently being implemented at KCP&L.

KCP&L SmartGrid Demonstration Project

KCP&L's SmartGrid Demonstration Project deployed an end-to-end SmartGrid (within Kansas City, MO) that includes a wide array of SmartGrid technologies and components. These were grouped into five (5) major sectors: Smart Distribution, Smart Metering, Interoperability and Security, Smart End-Use and Smart Generation. The DOE portion of the project was completed in 2015, with decommissioning of immature technologies through mid-2016. The final report was filed with the DOE in 2016. Refer to Section 4.3.1.1 for SmartGrid Demonstration Project discussion and a weblink to the Final Report filed with the DOE.

4.6.3 DISTRIBUTION ADVANCED GRID TECHNOLOGIES IMPACT DESCRIPTION

2. A description of the impact of the implementation of distribution advanced grid technologies on the selection of a resource acquisition strategy; and

The implementation of (or lack thereof) distribution advanced grid technologies did not influence the selection of the resource acquisition strategy presented in this filing.

SECTION 5: UTILITY AFFILIATION

(5) The electric utility shall identify and describe any affiliate or other relationship with transmission planning, designing, engineering, building, and/or construction management companies that impact or may be impacted by the electric utility. Any description and documentation requirements in sections (1) through (4) also apply to any affiliate transmission planning, designing, engineering, building, and/or construction management company or other transmission planning, designing, engineering, building, and/or construction management company currently participating in transmission works or transmission projects for and/or with the electric utility.

On April 4, 2012 Great Plains Energy ("GXP"), the holding company for both KCP&L and GMO, and American Electric Power ("AEP") announced the formation of a company to build and invest in transmission infrastructure. The new company, Transource EnergySM LLC ("Transource"), will pursue competitive transmission projects in the SPP region, the MISO and PJM regions, and potentially other regions in the future. GXP owns 13.5 percent of Transource through its newly-formed subsidiary, GPE Transmission Holding Company, LLC ("GPETHCO"). AEP owns the other 86.5 percent of Transource through its subsidiary, AEP Transmission Holding Company, LLC ("AEPTHC").

At this point, it is GXP's intent to pursue, develop, construct, and own through GPETHCO's interest in Transource – rather than through KCP&L and/or GMO – any future regional and inter-regional transmission projects subject to regional cost allocation. While it is premature to determine the specific impact on the regionally allocated costs resulting from constructing projects within Transource, it is anticipated that the partnership between GXP and AEP will provide for a financially-strong, cost-competitive, and technically-proficient transmission development entity. The scale, execution experience, and engineering expertise that Transource expects to be able to bring to the projects should provide benefits to customers through lower construction costs, better access to capital, and operational efficiencies.

SECTION 6: FUTURE TRANSMISSION PROJECTS

(6) The electric utility shall identify and describe any transmission projects under consideration by an RTO for the electric utility's service territory.

SPP is scheduled to complete another ITPNT in 2018, although projects have not yet been identified for consideration. SPP is scheduled to begin the first cycle of their new annual planning process, scheduled for completion in 2019, thus there are no transmission projects under consideration at this time.