VOLUME 4.5

TRANSMISSION AND DISTRIBUTION ANALYSIS

KANSAS CITY POWER & LIGHT COMPANY (KCP&L)

INTEGRATED RESOURCE PLAN

4 CSR 240-22.045

APRIL, 2015

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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 2015 ITP10 process – a voltage conversion of the Iatan – Stranger Creek 161 kV transmission line to 345 kV. A need date was set at 1/1/2019.
- SPP identified one reliability project in the KCP&L footprint through its 2015 ITPNT process – an upgrade to the 161/69 kV transformer at South Waverly. A need date was set at 6/1/2015.
- A total of five transmission projects have been identified in the KCP&L territory, with need dates between 2015 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 <u>OPPORTUNITIES TO REDUCE TRANSMISSION POWER AND ENERGY LOSSES</u>

(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 $862,200 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 2015 summer peak conditions are shown in Table 1, below.

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

TRANSMISSION LINES		2015 SP Flow	LINE IMPEDENCE			LINE	
FROM	TO	MW	R	X	B	MILE	
				1192 ACSR CONDUCTOR			
MARTCTY5	STHTOWN5	203.2	0.00339	0.02230	0.01170	7.76	
WGARDNR5	MOONLT 5	197.4	0.00188	0.01692	0.00928	6.04	
RNRIDGE5	NASHUA-5	169	0.00202	0.01750	0.00930	6.10	
CRAIG 5	LENEXAN5	162.8	0.00100	0.00840	0.00460	3.00	
STILWEL5	HICKMAN5	159.4	0.00460	0.03870	0.02050	13.54	
			TOTAL KCP&L LOSSES AT PEAK LOAD				65.2
				1192 BUNDLED CONDUCTOR			
MARTCTY5	STHTOWN5	236	0.00170	0.01115	0.01630	7.76	
WGARDNR5	MOONLT 5	217.6	0.00094	0.00846	0.01268	6.04	
RNRIDGE5	NASHUA-5	202.4	0.00101	0.00875	0.01281	6.10	
CRAIG 5	LENEXAN5	179.6	0.00050	0.00420	0.00630	3.00	
STILWEL5	HICKMAN5	200.5	0.00230	0.01935	0.02843	13.54	
			TOTAL KCP&L LOSSES AT PEAK LOAD				63.1
MW LOSS REDUCTION using 1192 BD conductor in KCP&L							2.10
TOTAL LINE MILES							42.5
TOTAL COST TO RECONDUCTOR/REBUILD AT $862,200 PER MILE							$36,626,256
AVERAGE COST OF LOSS REDUCTION					$/KW		$17,441

The average cost of loss reduction for these five transmission lines is $17,441/kw. This is approximately five 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 2015 summer peak load conditions is only 1.7%. The comparative value for the rest of the Southwest Power Pool (SPP) is 2.43%.

Table 2: SPP 2015 Transmission Losses by Area

AREA	Load Mw	Loss Mw	% Loss
515	667.3	20.6	3.1%
520	10168.0	234	2.3%
523	1102.0	21.8	2.0%
524	6197.7	136.6	2.2%
525	1568.4	44.1	2.8%
526	6252.7	201	3.2%
527	356.8	0.4	0.1%
531	440.9	9	2.0%
534	1302.4	33.7	2.6%
536	5817.2	133.4	2.3%
540	2054.5	29.9	1.5%
KCP&L	***3942.8***	***65.2***	***1.7%***
542	501.7	2.2	0.4%
544	1138.9	31	2.7%
545	306.3	2.5	0.8%
546	772.4	10.5	1.4%
640	3778.7	140.7	3.7%
645	2787.0	34.6	1.2%
650	766.7	8.7	1.1%
SPP	49922.4	1159.7	2.3%

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 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. 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 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 Tiffany Springs, Cedar Creek, and Riley 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, not only 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 inaccurate watt-var charts or costly 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.

As KCP&L builds toward its own future here in Kansas City, 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.

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

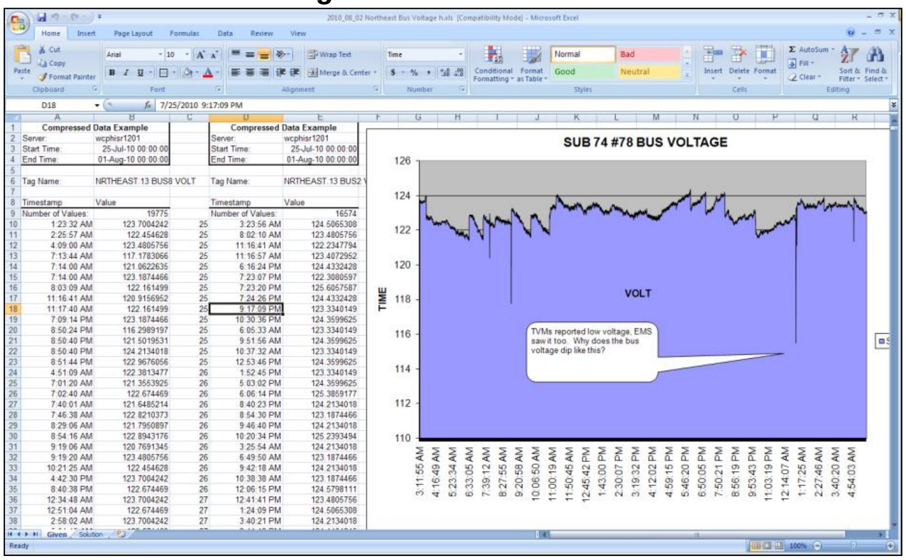
Category	Study Name	Deliverable
Capacity	Load Preservation 5 Yr. System Expansion – Load Device Weather Adjustment 20 Year Forecast Circuit Rating Study	Black Start Plan Budgetary Recommendations Distribution Load Book Forecasted Substation Loads Circuit Rating utilized for Operational Guidance
Contingency	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.

<u>PI/Network Manager</u>

During the summer of 2010, the new Network Manager Energy Management (SCADA) system was placed in-service. With this ABB product KCP&L also acquired the PI Historian data archive, which now contains device loads and other historical system characteristics. Once all system components are merged into the new system, the PI Historian will be the primary archive for engineers to find and extract load and voltage history. The figure below provides a snapshot of PI Historian.

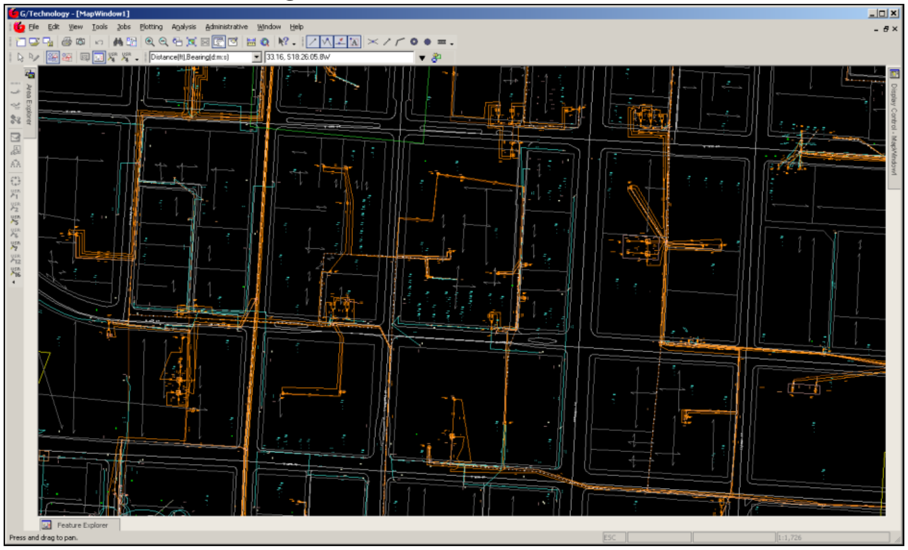
Figure 1: PI Screenshot



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 SynerGEE. Device characteristics and connectivity drive load-flow models in use by Distribution Planners. The figure below provides a snapshot of G/Tech.

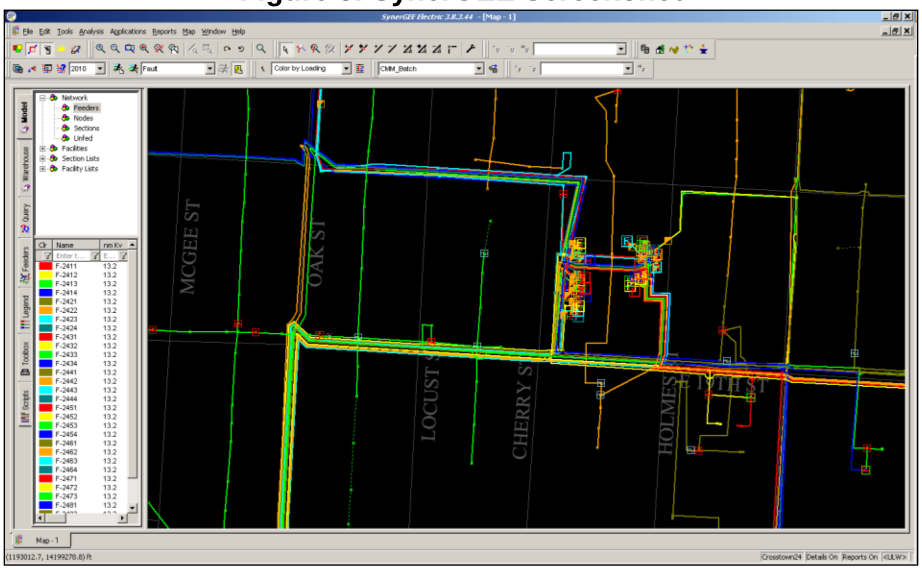
Figure 2: G/Tech Screenshot



SynerGEE

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 SynerGEE. The figure below provides a snapshot of the SyngerGee software program.

Figure 3: SynerGEE Screenshot



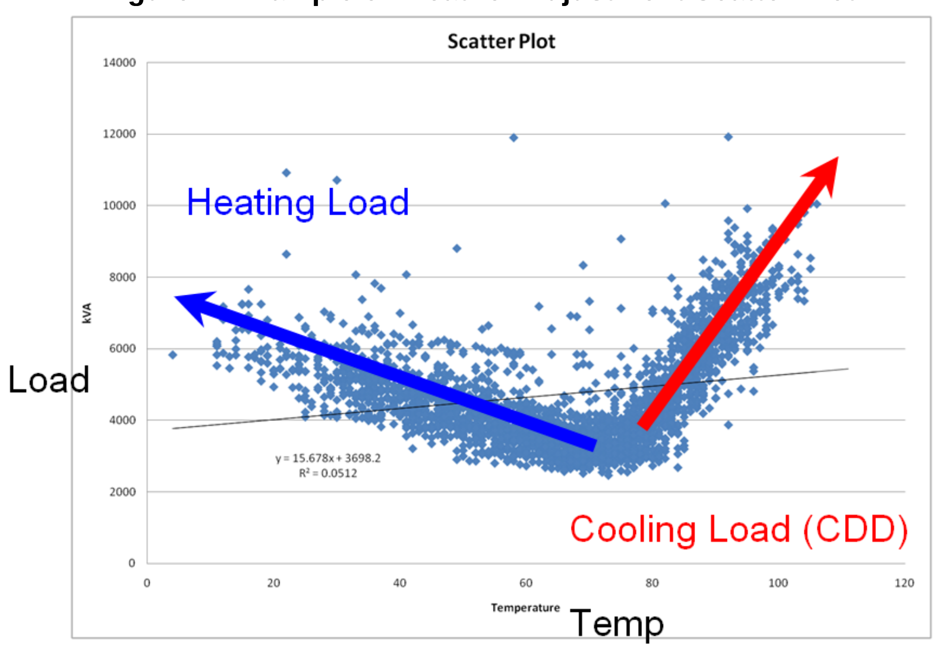
1.1.2.1 Capacity Planning

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

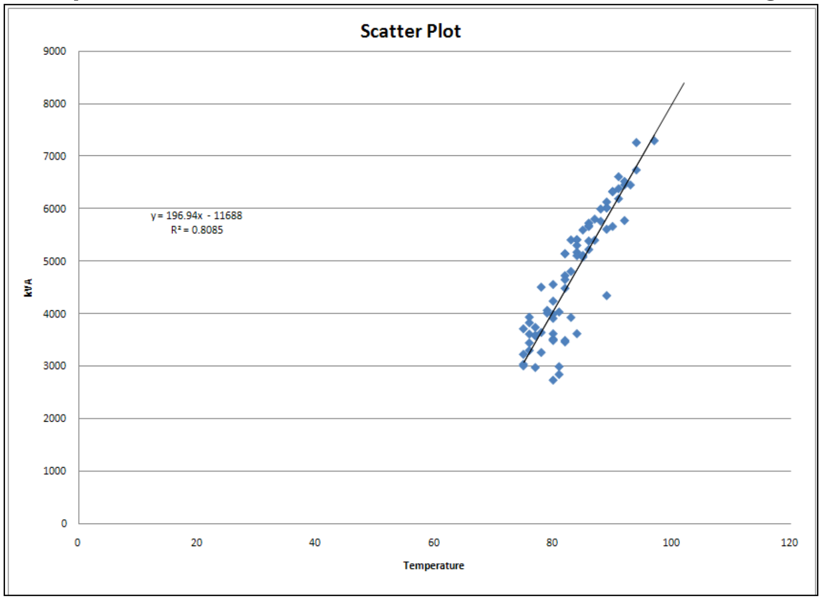
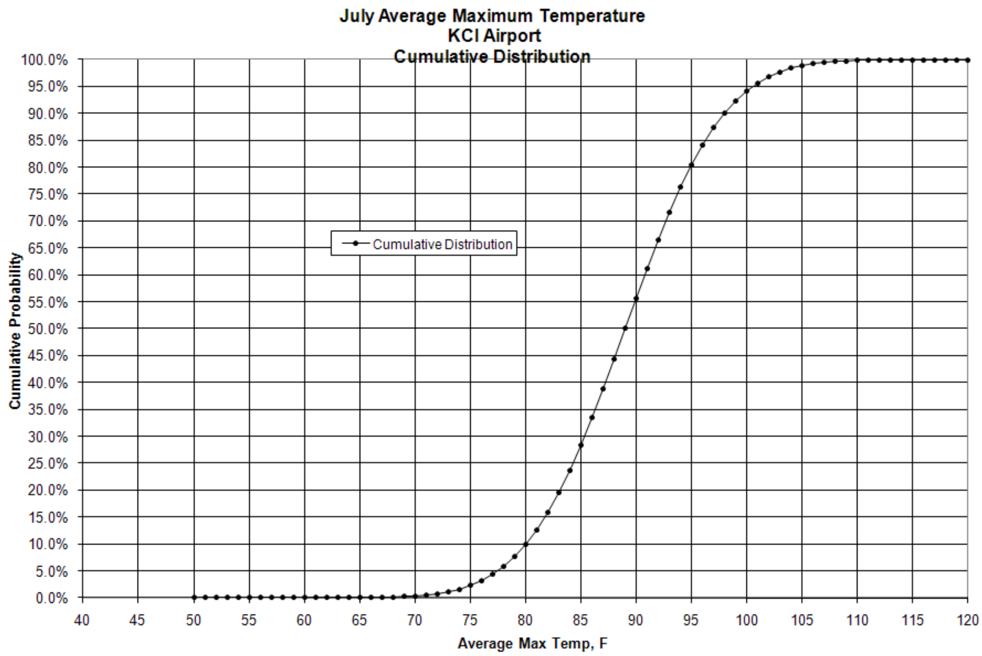


Figure 6: Cumulative Distribution Plot - 95% certainty at 100 degrees F



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.

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 Spatial Electric Load Forecast Study (Electric Vehicle Study)

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.

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 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.A contains a complete copy of the “Spatial Electric Load Forecast Study”.

1.1.2.2 <u>Contingency Planning</u>

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 <u>N-1 Contingency</u>

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. SynerGEE 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. SynerGEE, using G.I.S. models exported from GTech and weather-adjusted load data, actually determines how that load is spread across the circuit by taking a third input from the C.I.S. – metered customer load data. The SynerGEE CMM Module allows Distribution Planning to allocate feeder breaker weather-adjusted load on a given feeder based upon how it appears by its metered customer load, which is typically measured in kWh.

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 SynerGEE, 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 SynerGEE 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 and Light Electric System Loss Analysis”, can be found in Appendix 4.5.B.

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.C.

1.1.2.3.3 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 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 program uses a mix of analysis techniques. One technique does partial discharge testing of entire underground loops and replaces the cable sections that do not pass this test. Another option is to look at the number of failures on the loop and calculate the number of segments that have had failures. If this percentage is greater than 40%, the cable segments on the entire loop are eligible for replacement. These methods provide targeted proactive cable replacements based on cable condition or failure history. The goal is to target high-risk cables, and replace these cable segments before failure.

The reactive cable replacement program requires replacement of a cable when it has failed two or more times. The current policy of the reactive URD replacement program is to replace any direct buried cable after its second failure with cable in conduit. A section of cable receives a priority which is a function of the number of customers affected by the cable outage, the duration of the outage, the vintage of the cable, the number of failures of cable, the time elapsed from the most recent failure, and the number of outages that the lateral has experienced in past 12-months.

1.1.2.4.2 Cable Injection Program

In addition to cable replacement, cable injection proactively addresses high-risk cables. Cable injection techniques prolong the cable's life and improve reliability. Injection can be performed on cables that have faulted, but as with proactive replacement, the goal is to prevent failures from happening in the first place. 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.

1.1.2.4.3 Worst Performing Circuit Analysis

The inventory assessment projects have given Kansas City Power and Light an advantage that we can employ with worst performing circuit analysis. Annually, we identify worst performing circuits as mandated by the MPSC and develop reliability plans and make repairs. The performance of circuits varies significantly and no two of them have identical problems to fix. We use the assessment data to be included in our analysis of those worst performing circuits. There are approximately 70 to 80 WPC's under review each year that covers Missouri and Kansas's regulatory rules. Pole Replacement and Reinforcement Program

1.1.2.4.4 Pole Replacement and Reinforcement Program

The Distribution Pole Replacement/Reinforcement Program addresses reliability issues associated with the condition of distribution poles. Per MPSC mandate, 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 conditions with the greatest risk to safety and impact to customer reliability. Annual pole rejection rate is calculated to be 0.0356% per 1,000 pole inspections.

1.1.2.4.5 Lateral Improvement Program

This program is an organized effort to evaluate the performance of all laterals on our system. The criteria considered for fuse lateral selection are customer interrupted and outage frequency. Examples shown in Figure 8 below are all laterals to consider for analytical reviews to determine critical value. The blue circle drawn around the areas with the highest critical values is the chosen laterals. Laterals tagged as critical value represents 0.9% of the total. Figure 8 show customers interrupted ranges starting at 400 customers interrupted (CI) down to less than 49 CI per event. Frequency rate is identified by using letters starting with (A), (B), (C), and (D). Each letter category represents 25% of the total frequency rate equal to 100%. The numbers within the figure are lateral counts in each category. For instance, IR (1-2) means one or two outage events occurring on a lateral. The selection scheme has proven to be the best approach.

Figure 8

Criteria for Fuse Lateral Selection - Critical Values				
	Frequency Rate			
Customers Interrupted	**A IR(1-2)**	**B IR(3-5)**	**C IR(6-7)**	**D IR> (8)**
400-300	13			
299-200	45	4		
199-100	250	24	1	
99-50	600	63	2	1
49<	5,062	312	8	1
Totals	5,970	403	11	2

1.1.2.4.6 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.

1.1.2.4.7 Mobile Substations

Asset Management is also looking into the purchase of 2 mobile substation units to reduce the risk of long-term power outages in the event of a failure of a high-voltage substation transformer. Presently, there is a need for several units with various capacities and voltage levels in addition to the mobile units KCP&L and KCP&L GMO currently have in their fleet. Purchase of these additional units will provide greater operational flexibility while also minimizing spare transformer inventory throughout KCP&L's service areas.

1.2 ASSESEMENT 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;

KCP&L Transmission Planning must plan to meet interconnection needs of transmission customers for connection to and use of the KCP&L transmission system. The Interconnection procedures are covered within the Federal Energy Regulatory Commission (FERC) approved transmission tariff provisions where customers are provided detailed transmission studies and interconnection estimates for connecting to and using KCP&L's transmission system.

An example of such is the 2014 review of potential sites for addition of new KCP&L generation resources that considered large additions (620 MW combined cycle units), medium size additions (200 MW simple cycle units), and small incremental additions (100 MW reciprocating engine units). This process included review of brown field (existing) and green field (new) sites within or near the KCP&L and GMO service territories. KCP&L 161 kV transmission lines are generally not adequate to provide firm transmission for a 620 MW generation resource unless multiple (2+) transmission lines are available for generation outlet. KCP&L 345 kV transmission lines can generally provide firm transmission for a 620 MW generation resource if there is available transmission capacity.

The resource siting study identified potential sites for addition of large, mid, and small generation resources. Transmission Planning provided a range of transmission costs for each site and identified potential transmission limitations.

Any KCP&L generation resource addition that would impact transmission level (>60 kV) flows would have to proceed through the SPP Generation Interconnection process before it could be interconnected to the 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 ASSESSMENT OF TRANSMISSION UPGRADES FOR POWER PURCHASES

(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 North American Electric Reliability Corporation (NERC) Regional Entity, SPP oversees enforcement and development of reliability standards. SPP has members in nine states. As a member of SPP, KCP&L participates in the regional transmission expansion plan processes of the RTO. Two recent expansion plan processes conducted by SPP are the Balanced Portfolio (June 2009) and the Priority Projects (April 2010).

The Balanced Portfolio is an SPP strategic initiative to develop a grouping of economic based regional transmission upgrades that benefit the SPP region while allocating the cost of the upgrades regionally. Projects in the Balanced Portfolio include transmission upgrades of 345 kV projects that will provide customers with potential savings that exceed project costs. These economic upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. Economic upgrades may provide other benefits to the power grid; i.e., increasing reliability and lowering required reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources. SPP analyzed the benefits and costs of the Balanced Portfolio and established that these projects provided a region-wide per-customer average benefit of $1.66/month with a corresponding cost of $0.88/month. The Balanced Portfolio included a total of seven transmission projects with an estimated engineering and construction cost of approximately $700 million (initial estimate). Two of these projects are within the KCP&L service territory. They are the Iatan – Nashua 345 kV line (~$65 million) and the Swissvale-Stilwell tap at West Gardner (~$2 million).

In the Priority Projects plan, SPP sought to identify, evaluate, and recommend transmission projects that would improve regional production costs, reduce grid congestion, enable large-scale renewable resources (primarily wind), improve the Generation Interconnection and Aggregate Facility Study processes, and better integrate SPP's east and west regions. A total of six transmission projects with an estimated cost of $1.1 billion were selected for construction in the Priority Projects process providing a variety of benefits to the region. One of the projects included is a GMO project as the Nebraska City-Mullin Creek-Sibley 345 kV transmission line. These Priority Projects achieve the strategic goals of reducing transmission congestion, improving the Aggregate Facility Study process by creating additional transfer capability and increasing the ability to transfer power in an eastward direction for the majority of the transmission paths between SPP's western and eastern areas.

The costs for the Balanced Portfolio and Priority Projects will be allocated on a regional basis by specific allocation methods whether or not KCP&L makes any resource additions. For this reason, KCP&L's share of the allocated costs for Balanced Portfolio and Priority Projects were not reflected in the analysis of preliminary supply-side candidate resource options.

The preferred resource plan for KCP&L includes additional wind and solar generation resources. The solar resources are relatively small amounts of generation and are assumed to be interconnected at the distribution voltage levels. For this reason there is no associated transmission interconnection or upgrade costs for these solar generation resources. The wind resources remotely located in western Kansas will utilize regional transmission capacity and transmission service to deliver their output to KCP&L loads. Any new generation resources would have to apply for interconnection through the SPP generator interconnection process and apply for transmission service in the SPP Aggregate Study process.

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

(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.

In anticipation of retirement of the CellNet fixed network system due to it's replacement with a new AMI mesh network, KCP&L has contracted with Sensus to pilot their Flexnet communications system. Flexnet utilizes cellular radio technology, but on a private cellular network rather than commercial cellular coverage. The original target for Flexnet will be to replace the Cellnet communications up through the second half of 2015. KCP&L will evaluate the Flexnet pilot to determine if it can be economically expanded for greater coverage.

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

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 for this project is 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. KCP&L performed various proof of concept tests on the use of DVC to reduce demand on system peak. The tests showed a reduction of 0.92% MW reduction for each 1.0% voltage reduction upon system peak. This extrapolates to nearly 50 MW reduction on the KCP&L metro system during summer peak conditions.

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, which includes all or parts of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. Successful implementation of the ITP will result in a list of transmission expansion projects and completion dates that facilitate the creation of a reliable, robust, flexible, and cost-effective transmission network that improves access to the region's diverse resources, including its vast potential for renewable energy. Significant wind energy development is taking place in parts of Oklahoma, Kansas, Nebraska, and Texas.

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.

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 second iteration of the 10-Year Assessment (ITP10) was conducted in 2013-2014, with the final report issued in January 2015. Two distinct futures were considered to account for possible variations in system conditions: (1) business-as-usual, which includes all statutory/regulatory renewable mandates and goals resulting in 11.5 GW of renewable resources modeled in SPP, load growth projected by load serving entities, and SPP member-identified generator retirement projections, and (2) decreased base load capacity, which considers factors that could drive a reduction in existing generation. The recommended 2015 ITP10 portfolio was estimated at $273 million engineering and construction cost and includes projects needed to meet potential reliability, economic, and policy requirements. These projects, with a total estimated net present value revenue requirement of $334 million, are expected to provide net benefits of approximately $1.4 billion over the life of the projects under a business-as-usual scenario containing 10.3 GW of wind capacity expected to be contracted by SPP members. Project need dates were identified between 2019 and 2024. KCP&L received one transmission project as a result of the ITP10 study – a voltage conversion of the current Iatan – Stranger Creek 161 kV line to 345 kV. SPP identified the need date for this upgrade as 1/1/2019.

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 2014, with the final report issued in January 2015. The 2015 ITPNT used two scenario models built across multiple years and seasons to account for various system conditions across the near-term horizon. The first scenario contains projected transmission transfers between SPP legacy BAs and generation dispatch on the system. The second scenario maximized all applicable confirmed long-term firm transmission service with its necessary generation dispatch. Additionally, a Consolidated Balancing Authority (CBA) model scenario was built across the same years and seasons to show the needs on the SPP transmission system as a result of a Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED). 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 potential reliability violations. Staff presented these solutions for member and stakeholder review at SPP's December 2014 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 needed in the years 2015-2020 totaled $248.2 million.   In the 2015 ITPNT assessment, an upgrade to the S. Waverly 161/69kV transformer was selected as the solution to six unique reliability needs, four in KCP&L and two in GMO. SPP identified the need date for this upgrade as 6/1/2015.

The ITP process has been a fundamental change in the way in which transmission planning occurs in the SPP region. This process, with its iterative nature and wide range of planning periods, helps to ensure robust planning, lowest cost solutions and a reliable bulk electric grid for the region. It also strengthens the balance between future needs of the system with an ever-changing grid topology, load growth, generation resources, energy policy and planning criteria.

3.1.2 TRANSMISSION ASSESSMENT FOR ADVANCE TECHNOLOGIES

2. Assessment of transmission upgrades to incorporate advanced technologies;

KCP&L currently makes use of four advanced technologies in its transmission system; Real Time Line Rating, Hybrid Structure Design, Solid Dielectric Cables, and Fiber Optic Shield Wire.

KCP&L currently uses a commercial application, based upon actual conductor tension, to provide real time line ratings for two of the more critically loaded 345 kV transmission lines. Basing the ratings upon a direct measurement of the actual conductor tension is the most direct method currently available to establish real time (dynamic) conductor ratings, and using the conductor tension captures all of the local conditions that affect the conductor tension and current carrying capacity. The real time line ratings are provided not only to our Transmission System Operators but also to the SPP Reliability Coordinator. This equipment allows transmission lines to carry more power when conditions are favorable and reduce transmission congestion.

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	ANNUAL TRANSMISSION REVENUE REQUIREMENT ALLOCATED TO KCP&L
2015	$ 34,055,762
2016	$ 37,509,508
2017	$ 42,874,706
2018	$ 48,640,102
2019	$ 52,219,837
2020	$ 52,602,949
2021	$ 53,879,998
2022	$ 53,677,035
2023	$ 52,613,087
2024	$ 50,997,005
2025	$ 49,380,922

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.

3.1.5 <u>REVENUE CREDITS ESTIMATE</u>

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

Estimated Transmission Service revenue that KCP&L will receive is based on the amounts included in FERC account 456100.

Table 5 below shows historical and projected amounts for account 456100 for 2012-2025. The revenue credit process for future regional transmission upgrades has not been fully developed by SPP at this time and is not included in these projections.

Table 5: KCP&L Transmission Service Revenues from SPP

YEAR	TS REVENUE	BASIS
2012	$10,080,825	actual
2013	$8,402,688	actual
2014	$9,135,432	forecast
2015	$8,989,824	budget
2016	$8,989,824	projected
2017	$8,989,824	projected
2018	$8,989,824	projected
2019	$8,989,824	projected
2020	$8,989,824	projected
2021	$8,989,824	projected
2022	$8,989,824	projected
2023	$8,989,824	projected
2024	$8,989,824	projected
2025	$8,989,824	projected

3.1.6 <u>TIMING OF NEEDED RESOURCES ESTIMATE</u>

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 SPP Balanced Portfolio of regional transmission projects included two projects in the KCP&L service territory. The Swissvale – Stilwell 345 kV tap at West Gardner and the Iatan – Nashua 345 kV line are primarily economic-based transmission projects. The Swissvale – Stilwell 345 kV tap at West Gardner was placed into service on 1/1/2013. The expected in-service date for Iatan – Nashua 345 kV is 6/1/2015.

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.

These projects were identified within the SPP transmission planning process to reduce transmission congestion and provide regional production costs and trade benefits. 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 such as the SPP Balanced Portfolio, 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 Iatan-Nashua 345kV project in KCP&L's territory, it is a project that will significantly reduce congestion of a major regional flowgate near the Kansas City-north area and directly relieves growing limitations on the ability to dispatch KCP&L's new Iatan 2 generating unit. The Iatan – Nashua project also provides approximately 8 Mw of loss reduction for the KCP&L and GMO transmission system at peak load conditions. Iatan – Nashua also eliminates two flowgates; one on the KCP&L – Westar boundary and one on the GMO – KCP&L boundary.

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.

2009 Balanced Portfolio - Final Approved Report.pdf (Appendix 4.5 - 3.3A)

Priority Projects Phase II Rev 1 Report - 4-27-10_final.pdf (Appendix 4.5 - 3.3B)

20130730_2013_ITP20_Report_clean.pdf (Appendix 4.5 - 3.3C)

Final_2015_ITP10_Report_BOD_Approved_012715 .pdf(Appendix 4.5 - 3.3D)

Final_2015_ITPNT_Assessment_BOD_Approved.pdf (Appendix 4.5 - 3.3E)

2015_STEP_Report.pdf (Appendix 4.5 - 3.3F)

2015_STEP_Project_List_Protected (Appendix 4.5 – 3.3G)

The Balanced Portfolio and Priority Projects reports are described in Section 1.3 above. The ITP20, ITP10, ITPNT reports are described in Section 3.1.1 above. The 2015 SPP Transmission Expansion Plan (STEP) Report and Project List summarize 2014 activities that impact future development of the SPP transmission grid. Seven distinct areas of transmission planning are discussed in this report, each of which are critical to meeting mandates of either the 2011 SPP Strategic Plan or the nine planning principles in FERC Order 890. These areas are Transmission Services, Generation Interconnection, Integrated Transmission Planning, Balanced Portfolio, 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.

Generally speaking, generator interconnections for green field sites will require a three breaker ring bus substation for interconnection to the existing transmission system. Estimated costs for the interconnecting substation are in the range of $8-10 million at 345kV and $4-8 million at 161kV. Costs for interconnection of new generation resources at existing substations are generally significantly less due to the availability of existing substation infrastructure.

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 three 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 decline to pay their portion of the allocated cost and drop out of the study process. Study analysis is repeated on the reduced set of transmission service requests. This is an iterative process until a final set of transmission service requests for those customers remaining in the process has been reached. 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 2015 SPP Transmission Expansion Plan (STEP) is shown below in Table 6.

Table 6: KCP&L Transmission Upgrades 2015 SPP STEP

TRANSMISSION PROJECT	COST ESTIMATE	TYPE	DATE
Install new 345/161 kV transformer at Nashua	$4,620,000	Balanced Portfolio	06/01/15
Add 345 kV line terminal at Iatan. Add ring bus at Iatan to accommodate line terminals.	$10,811,309	Balanced Portfolio	06/01/15
Replace existing 161/69 kV transformer at South Waverly	$1,355,978	ITP	06/01/15
Iatan – Stranger Creek 345 kV Voltage Conversion	$16,119,446	ITP	01/01/19
Increase rating of Nashua transformer to 650/715.	$12,600,000	ITP	01/01/33

Total estimated construction cost for these transmission upgrades is $45,506,733.

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 2015 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 $
Install new 345/161 kV transformer at Nashua	$4,620,000	TBD	TBD
Add 345 kV line terminal at Iatan. Add ring bus at Iatan to accommodate line terminals.	$10,811,309	TBD	TBD
Replace existing 161/69 kV transformer at South Waverly	$1,355,978	100	$1,355,978
Iatan – Stranger Creek 345 kV Voltage Conversion	$16,119,446	7.8	$1,257,316
Increase rating of Nashua 345/161 kV transformer to 650/715.	$12,600,000	69.5	$8,757,000

The cost allocation between SPP members for Balanced Portfolio projects has not been determined at this time. A primary feature of the Balanced Portfolio cost allocation is to provide all SPP members a benefit/cost ratio of at least 1.0 and thus there will be revenue transfers in order to keep members at or above that threshold.

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 it's 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 pursuant to 4 CSR 240-22.045(4)(C).

KCP&L developed a DRAFT SmartGrid Vision, Architecture, and Road Map in 2008 as a potential guide to future KCP&L investments in advanced distribution technologies. The road map focused on the deployment of the advanced distribution technologies needed to implement the SmartGrid functions as described in Title XIII of the Energy Independence and Security Act of 2007 (EISA).

With the passage of the American Recovery and Reinvestment Act of 2009 (ARRA) in February 2009, it became apparent that the draft road map would be too aggressive and possibly limiting from a technical point of view. The architecture, on which the plan was developed, was based on prior EPRI Intelligrid research. It was unclear, to what extent, the NIST SmartGrid Interoperability Framework initiative funded by ARRA may change our future SmartGrid architecture design and technology selections.

With technology architecture uncertainties and an overly aggressive schedule of the ARRA funded SmartGrid Investment Grants (3 years), KCP&L management decided to focus on pursuing 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 project will end in the first half of 2015. The geographical components of the project all lie within Kansas City, MO.

Upon completion of the SmartGrid Demonstration Project KCP&L plans to use the findings of the project to enlighten KCP&L's technology vision, architecture, and road map that will provide the framework for evaluating feasibility of these and similar advanced technologies.

KCP&L will perform studies to optimize investments in advanced distribution that incorporates cost-benefit analysis to determine if a business case can be made for technology deployment. Learning from the SmartGrid Demonstration will be used in these analyses when appropriate.

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 OPTIMIZATION OF INVESTMENT – NON-MONETARY FACTORS

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

4.4.3.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4 OPTIMIZATION OF INVESTMENT – SOCIETAL BENEFIT

3. Societal benefit, including:

4.4.4.1 Societal Benefit – Consumer Choice

A. More consumer power choices;

4.4.4.1.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4.2 Societal Benefit – Existing Resource Improvement

B. Improved utilization of existing resources;

4.4.4.2.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4.3 Societal Benefit – Price Signal Cost Reduction

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

4.4.4.3.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4.4 Societal Benefit –

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

4.4.4.4.1 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).

4.4.6.1.1 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.

Upon completion of the SmartGrid Demonstration Project, KCP&L plans to use the findings of the project to enlighten KCP&L's technology vision, architecture, and road map that will provide framework for evaluating the feasibility of and guiding the implementation of advanced distribution grid technologies.

In developing the road map, KCP&L intends to use the build and impact metrics from our project and other industry sources to perform a cost/benefit analysis of advanced distribution grid technologies considered prior to implementation.

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. The previous response to section 22.045 (1)(D) describe how KCP&L applies these previously adopted advanced grid technologies to improve the operation of the distribution network.

DA – A 1993-1999 Strategic Initiative

In 1993, Kansas City Power & Light Company (KCP&L) management established an internal, interdivisional, multi-disciplined team to develop definitions, economic evaluations, recommendation plans for Distribution Automation (DA) at KCP&L. The team's purpose was to determine the feasibility of consolidating numerous existing, but independent, automation efforts that were undergoing evaluation throughout the company. Consequently, KCP&L management consolidated multiple DA efforts into one project and between 1995 and 1999 the following components of the DA vision were implemented.

- **AMR -** Automated Meter Reading**.** KCP&L implemented the first utility wide 1-way AMR system in the industry automating over 90% of all customer meters..
- **ACD/VRU** – Automatic Call Director with Voice Response Unit. Provides improved call handling capability for the Call Center and will provide a direct transfer of Outage Calls to the Outage Management System (OMS)
- **DFMS-AMFM/GIS** – Automated Mapping/Facilities Management/ Geographic Information System. Provides the functionality to support the mapping, record keeping and operation of the electrical system via a fully connected and geographically related model. KCP&L entered into data sharing agreements with 7 city and county entities to obtain the most accurate land base information available on which it's hard copy facility maps were digitized
- **DFMS-WMS –** Work Management System. Provides for automated job planning and management of resources.
- **DFMS-EAS –** Engineering Analysis System. Provides the functionality for analysis of the distribution systems electrical performance and plans for the necessary construction and maintenance of the system***.***
- **DFMS-TRS** Trouble Reporting System. Provides functionality to support the day-to-day trouble call tracking, outage analysis, and service restoration of the electrical distribution system. This system is now referred to as the OMS (Outage Management System).
- **DFMS-LDA -** Line Device Automation. Device Automation was initially limited to Capacitor Automation. Over 600 line capacitors have been automated and routinely maintain the urban circuits at nearly unity power factor.

Leveraging the DA Investment

Having successfully implemented the systems initiated by the DA Initiative, KCP&L identified, cost justified, and implemented a series of projects that leveraged the system implementations establishing greater process integration, operational savings and improved operational performance for customers. Many of these projects included first of its kind technology deployments within the utility industry.

- **AMFM/GIS Upgrade**. KCP&L became the first utility to port our vendors AMFM/GIS system from their production legacy CAD-RDBMS platform to a fully RDBMS platform.
- **AMFM/GIS to WMS Integration.** - Integration automated the population of GIS attributes based on the WMS compatible units. This functionality established the foundation for an eventual integrated graphic design function.
- **WMS Expanded to Maintenance Work. -** Use of the WMS was expanded from design-construction jobs to high volume maintenance and construction service orders, automating and streamlining those processes.
- **Account Link WEB portal integrated AMR and CIS –** The AccountLink customer web portal was established and daily AMR read information was made available to customers
- **AMR integrated with OMS**. AMR outage (last gasp) alerts and AMR meter ‘pings’ were implemented to improve outage and trouble response.
- **ORS dashboard integrated with OMS. -** Implemented the Outage Records System, an OMS data mining and management dashboard provides real time summary and overview of outage statistics. This system provides the real-time “Outage Watch” map on the KCP&L web page, www.kcpl.com.
- **MWFM Integrated with AMFM/GIS, OMS, and CIS** - Implemented the Mobile Work Force Management system which automated the field processing of Trouble, Outage, and CIS Meter Service Orders.

Comprehensive Energy Plan – 2004-2009

An element of the KCP&L plan involved infrastructure improvements to strengthen the overall reliability of our system and network. Our plan included the following programs involving distribution facilities to incorporate new advanced technologies for faster diagnosis and repair of service interruptions.

- **Distribution System Inventory Verification Program.** This program involves conducting a full overhead distribution system field inventory to verify and augment existing distribution asset information at the component level. The program for the combined KCPL & KCP&L GMO service territories was completed in 2011.
- **Network Automation.** The Network Automation Project involves monitoring of KCP&L's underground (UG) secondary networks. Automation of the network alerts engineers, dispatchers, and the underground workers to abnormal situations that can potentially cascade into larger problems if left unchecked.
- **"Integrated Circuit of the Future".** The "Integrated Circuit of the Future" project involved the field installation and testing of various distribution automation technologies to evaluate the feasibility of larger scale deployment on the KCP&L's distribution grid.
- **50 C.O. Relay Automation.** The 50 C.O. Automation Project involves remote enabling or disabling of the distribution feeder over-current relays in substations. The ability to turn the relays off under fair weather conditions result in a forty to fifty percent reduction in momentary outages–greatly improving reliability and customer quality-of-service. When turned on during storms, this system allows reclosing to save fuses and reduce outages.
- **Dynamic Voltage Control (DVC).** The program allows operators to reduce the substation voltage a predetermined amount for demand reduction (DR). As a result of successful testing of the DVC system on the Integrated Circuit of the Future, KCP&L accelerated implementation of the DVC system to all 203 metro Kansas City substation buses resulting in an estimated 60MW of peak demand reduction.
- **34-kV Switching Device Automation and Fault Indication.** Project involves installation of automated switching devices and fault indicators.

American Recovery and Reinvestment Act of 2009

In February 2009, Congress passed, and the President approved, American Recovery and Reinvestment Act of 2009 (ARRA). ARRA provided, among other recoverey act funding, the appropriations required the DOE and NIST to implement their legslative mandate established by Title 13 of EISA.

- NIST - $20 Million to fund Smart Grid Interoperability Framework.Initiative
- DOE - $3.4 billion to fund SmartGrid Investment grants
- DOE - $600 million to fund Smart Grid Demonstration Grants

As 2009 progressed, it became apparent that enterprise SmartGrid deployments may be too aggressive and possibly imprudent from a technical point of view. It was unclear how much the NIST Interoperability Framework initiative may change our planned architecture and technology selection.

With technology architecture uncertainties and resource limitations, KCP&L management decided to focus on pursuing a demonstration grant. The KCP&L SmartGrid Demonstration Project Application – Project Narrative is included as Appendix 4.5.D. The KCP&L project was selected in late 2009 and a contract with the DOE was subsequently awarded in September 2010

KCP&L plans to use findings of the SmartGrid demonstration project to enlighten KCP&L's technology vision, architecture, and road map that will provide framework for evaluating the feasibility of, and guiding the implementation of advanced distribution grid technologies.

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 have been grouped into five (5) major sectors: Smart Distribution, Smart Metering, Interoperability and Security, Smart End-Use and Smart Generation. Below are additional details within each of these sectors:.

- Smart Distribution
  - Distribution Management System (DMS) including Outage Management System (OMS) and Distribution SCADA
  - IP/RF 2 –way Field Area Network for communications
  - Advanced distribution applications
  - Smart Substation
- Smart Metering
  - Advanced Metering Infrastructure (AMI)
  - Meter Data Management system (MDM)
  - Integration between Customer Info System (CIS), MDM, AMI and OMS
  - Data Analytics
- Interoperability and Security
  - Enterprise Service Bus (ESB) flexible architecture
  - IEC 61850 Substation Communications
  - OpenADR Communications for Advanced Demand Response

    - Zigbee Smart Energy Profile (SEP) communications between meters and in-home devices
    - State of the art network and physical security
- Smart End-Use
    - Home Energy Management Portal (HEMP)
    - Home Area Network (HAN)
    - In-Home Display (IHD)
    - Time of Use (TOU) pilot rate
    - Electric Vehicle (EV) charging
- Smart Generation
    - Distributed Energy Resource Management (DERM) system
    - Demand Response (DR) programs
    - Utility-owned rooftop solar generation
    - Utility scale battery

One of the main goals of the demonstration project was to implement this wide array of technologies and systems and demonstrate the level to which they could be integrated and truly interoperable according to emerging governmental/industry standards. The back office IT integration and infrastructure components were a very significant part of the overall project. The high number of vendors involved and immaturity (and interpretability) of the industry standards proved challenging to the interoperability objective.

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.

The advanced distribution grid technologies being evaluated through KCP&L's SmartGrid Demonstration Project, are foundational, potentially enabling technologies that may provide traditional operational benefits to the utility while enabling new demand side management and pricing programs; integration of utility and customer owned distributed generation; greater grid utilization through increased monitoring and control of grid resources; and enhanced utilization of customer demand response capabilities.

KCP&L anticipates that the results of SmartGrid Demonstration Project and subsequent benefit cost analyses will determine that several of the advanced distribution grid technologies will be determined to be cost effective, or at a minimum we will understand under what conditions they become cost effective.

As a DOE Smart Grid Demonstration Project requirement, KCP&L produced its first and second Interim Technology Performance Reports (TPR) on December 31, 2012 and December 31, 2013 respectively. These documents summarized all achievements on the project through the respective dates. . Key topics include summaries of the project design, implementation,testing, analysis, and some lessons learned. Due to the voluminous size of these reports, they have not been included in the Annual Update, but can be downloaded from the following DOE website;

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

A third Interim Technology Performance Report will be produced in early 2015. This document will extend the 2013 interim report by providing greater detail regarding the results of the operational demonstrations conducted and summarize the corresponding benefits analysis performed using the DOE SmartGrid and Energy Storage Computational Tools. The report will conclude with a summary of the build and impact metrics reported to the DOE.

A project Final Technical Report will be produced in the first half of 2015 following the conclusion of the project and will synthesize all learnings from the entirety of project. KCP&L assumes the DOE will make it available on the same website listed previously.

SmartGrid Demonstration Project High Level Status

The demonstration project has completed all but its final phases: Decommissioning and Final Reporting. The final operational test was performed in November 2014. Components that will not continue are being decommissioned. Components that will continue are being moved into the appropriate production environment. Analysis for the remaining Technology Performance Reports is being performed for report issuance.

Present Roadmap Influence

Although the SmartGrid Demonstration project is not fully complete, learning has been applied to KCP&L's technology road map and business case development for several projects. KCP&L is already in process of implementing the following components in broader deployments:

- Advanced Metering Infrastructure (AMI)
- Meter Data Management (MDM)
- Outage Management System (OMS) upgrade
- Distribution SCADA “lite” integration of Sensus DA communications into the OMS Upgrade
- Enterprise Service Bus (ESB) architecture (Oracle Service Bus)
- Fault Location advanced distribution automation application as part of the OMS upgrade
- Electric Vehicle (EV) Charging Infrastructure
- Two-way communicating programmable thermostats
- Implemented a technical Project Management Organization (PMO) to manage technology projects and coordinate integration and interoperability

AMI and EV Charging are the only items in the above list where KCP&L is using the same vendor solutions as used in the demonstration, but implementation and operational lessons still apply in all cases.

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.

The SPP regional transmission planning process will begin another ITP10 planning cycle in 2015, to be completed in 2017, and an ITPNT to be completed in 2016, thus there are no transmission projects under consideration at this time.