VOLUME 4.5

TRANSMISSION AND DISTRIBUTION ANALYSIS

THE EMPIRE DISTRICT ELECTRIC COMPANY

4 CSR 240-22.045

CASE NO. EO-2013-0547

JULY 2013

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TRANSMISSION AND DISTRIBUTION ANALYSIS

4 CSR 240-22.045 Transmission and Distribution Analysis

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

SECTION 1 **ADEQUACY OF THE TRANSMISSION AND DISTRIBUTION NETWORKS**

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

1.1 Opportunities to Reduce Transmission Power and Energy Losses

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

Electrical losses in a transmission line are directly dependent on the amount of current flowing on the line in question as well as the specific characteristics of the line (conductor type, line length, etc.). Empire uses a combination of 161-kV, 69-kV, and 34.5-kV transmission lines for serving its respective substations. The majority of Empire's 161-kV transmission infrastructure utilizes H-frame structures with a 795 ACSR type conductor. The associated summer A and B ratings are 290 and 341 MVA, respectively. If/When a particular line segment studied is found to have become overloaded, Empire evaluates the possibility of bundling conductors on the structures. In doing so, the losses on the bundled circuit are now halved, due to the reduced impedance characteristics. The flow on each of the conductors is reduced thereby reducing the direct losses on the conductor. The process of bundling a conductor also doubles the capacity of the chosen conductor. The resultant summer A and B ratings for 795 ACSR are 579 and 682 MVA, respectively.

In evaluating Empire's transmission system losses, approximately 15.5 MW of a total of 33.9 MW is accounted for on the 161-kV system. This is primarily due to the topography of Empire's service territory mainly consisting of rural loads. The aforementioned topography does not necessitate the need to serve dense load pockets with much larger conductor types than 795 ACSR, such as 1192 ACSR used in urban load environments; however, Empire's topography necessitates longer distances to be reconductored/bundled once a line segment is identified as a required upgrade. An example of such would be Empire's 161-kV line connecting Tipton Ford #292 to Monett #383 Substations. This specific line is approximately 29 miles in length. A general cost comparative analysis of reconductoring the line requiring a rebuild versus bundling the conductor for minimal structural change-outs of the line yields is shown in *Table 4.5-1.*

Configuration	**R**	**X**	**B**	**Losses in 2013 SP Model (in MW)**	**Difference (in MW)**
795 ACSR	0.0131	0.0856	0.0422	2.52	
2-795 ACSR	0.0065	0.0428	0.0211	2.32	0.2
2-566 ACSR	0.0093	0.0617	0.0585	2.43	0.09
Estimated cost to reconductor/bundle entire circuit:				$14,825,000	
Average cost per kW of loss reduction:				2-795 ACSR	$109,125
				2-556 ACSR	$242,500
Ratio of Avoided Transmission Costs (@ $82.73 / kW):				2-795 ACSR	1,319 : 1
				2-556 ACSR	2,931 : 1

Table 4.5-1 - Comparative Costs of Reconductoring versus Conductor Bundling of 161-kV Line

If dual bundled 795 ACSR or dual bundled 556 ACSR were chosen as a loss reduction option, the cost for this specific line is $109,125/kW and $242,500/kW, respectively. As related to the avoided transmission costs, the ratios are 1,319 and 2,931, respectively. These ratios exhibit the cost ineffectiveness of transmission loss reduction.

Empire's system losses (in MWs) represent approximately 2.9 percent of the losses evident in the projected 2013 summer peak model of the entire SPP footprint. When compared to like-configured systems (i.e., comparable size and topography), Empire's system losses are below the mean, as shown in *Table 4.5-2.*

Area	Load	Losses	% Loss
523	1032	16.62	1.6%
525	1468	56.36	3.8%
534	1167	63.55	5.4%
540	2004	30.53	1.5%
Empire	1180	33.24	2.8%
Averages	1370	40.06	3.0%

Table 4.5-2 - Empire's System Losses

With respect to the distribution level, Empire has taken measures to standardize their construction efforts in stocking commonly used conductors within the industry. One example is the evaluation and subsequent restricted use of redundant conductor types. 4/0 ACSR was a commonly used conductor in past installations alongside 336 ACSR. The structural requirements are much the same for either conductor type, however, the ampacity of 336 ACSR as compared to 4/0 was 519 and 366 amps, respectively (per Southwire's Overhead Conductor Manual, 2nd Edition). Not only were gains had in the ampacity of the likened conductors, but also loss gains made. *Table 4.5-3* provides a comparison of these conductors.

	Ohm / mi at 75 C	Ampacity (amps)
4/0 ACSR	0.5999	366
336 ACSR	0.3298	519

Table 4.5-3 - Comparison of Conductors of Interest

In standardizing to a 336 ACSR conductor versus the previously used 4/0 ACSR, line losses were reduced while the capacity of the wires increased. In doing so, capital projects on the distribution level are able to be delayed, more readily available switching paths are gained, and system flexibility increased.

1.1.1 **Distribution System Overview**

Empire has a single planning group tasked with transmission and distribution planning efforts. This planning group analyzes data, develops electrical models representative of the Empire distribution system, and performs associated power flow studies to assess and prioritize system improvement needs as system dynamics dictate. Empire maintains distribution voltages of 25-kV, 12.47-kV, and 4.16-kV three-phase as well as a mixture of open wye (dual-phase) and single-phase feeders. These feeders are composed of an assortment of conductor types and configurations.

The majority of the Empire distribution system mirrors that of a rural area co-op. Many of Empire's distribution feeders are long in length and have a distributed load profile. The average total distribution feeder exposure length within the Empire footprint is approximately 11 miles. This distance encompasses the total circuitry length (i.e., all trunk lines, taps, radials, etc.). The average length of overhead three phase of all Empire distribution circuits is 7.21 miles. The highest density loads are located in the Joplin and Branson areas. 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. The limited availability of switching paths is the largest factor in restoration efforts as well as feeder relief. The Empire distribution system is configured as a radial fed system under normal operating conditions. Empire maintains three auto throw schemes in different parts of the system (Joplin and Branson in Missouri, and Welch, Oklahoma) where alternate switching paths with available capacity are readily available. These type systems have limited applicability due to the typical Empire distribution circuit being rural in character.

Expansion of the distribution network occurs in load pockets of expansive development (i.e., subdivision expansion, large industrial customer development on greenfield sites, etc.). System expansion typically occurs on a smaller scale in magnitude; however, with the addition of these types of incremental load additions, the existing infrastructure is impacted more heavily due to the voltage profile drastically changing from the application of spot load(s) applied to the circuit. Empire constantly evaluates possible economic development projects and their associative impacts on the available distribution feeders, power transformers, and existing customer voltage profiles so as to determine what specific large scale upgrades are needed for a specific project of interest.

Empire's planning department also maintains distribution feeder models. Empire is presently migrating to new distribution evaluation software and currently integrating the available mapping resources to better model the distribution systems. The new model will allow for detailed evaluations as data becomes available so that as expansion occurs and load reconfigures, projects may be identified and prioritized accordingly.

1.1.2 **Annual Scope of Work**

Throughout each year, Empire's planning department prepares a number of system studies to determine weaknesses or risks and to assess the overall adequacy of their distribution system. The majority of the work focuses on increasing reliability and prioritizing work based upon cost, scope, impact, and effectiveness. This work encompasses four specific areas which include capacity, contingency, voltage, and condition. Empire uses a variety of tools to conduct these types of evaluations, including software such as Google Earth Pro, CYME International's Power

Engineering Solutions, and GTI geospatial analysis and viewing.

Figure 4.5-1 provides a screenshot from Google Earth Pro.

Figure 4.5-1 - Google Earth Pro Screenshot

Google Earth allows for an overhead view of an area and indicates general distances to be measured for line paths and proximity to alternate switching paths. Allowing for a view of the topography and attempting to head off any construction hindrances has proven effective on past projects. Projects imposed over the Google Earth snapshots allow those with a vested interest in the job to gain further knowledge of the scope of work to be done.

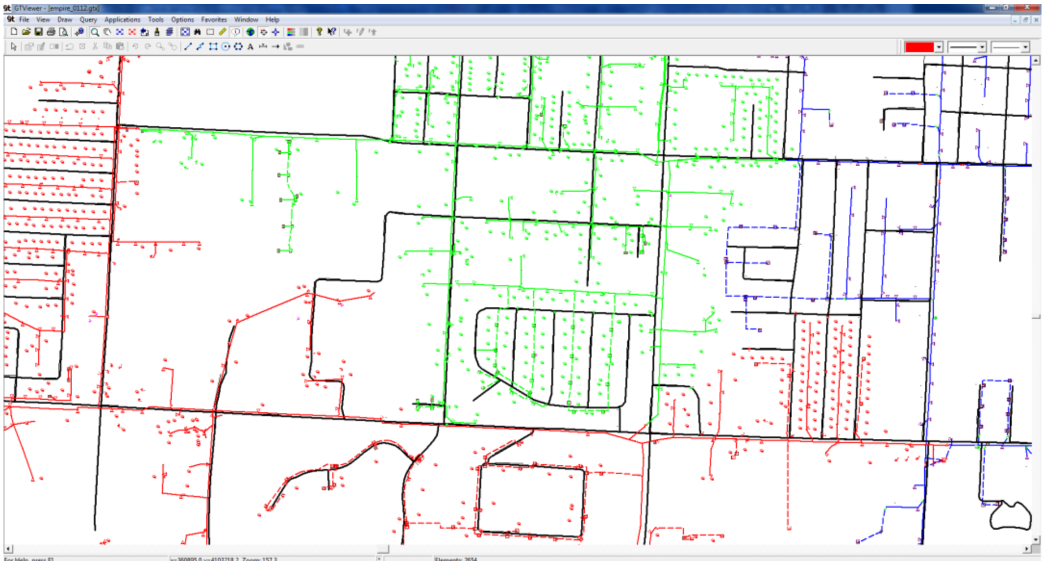

Figure 4.5-2 - GTViewer Screenshot

Figure 4.5-2 provides a screenshot from GTI's GTViewer. This software allows engineers to acquire model data for use in distribution analysis software, CYMDIST. GTI's software device characteristics and connectivity drive load-flow models in use by Empire's planning department.

Figure 4.5-3 below provides a screenshot from CYM Distribution System Analysis.

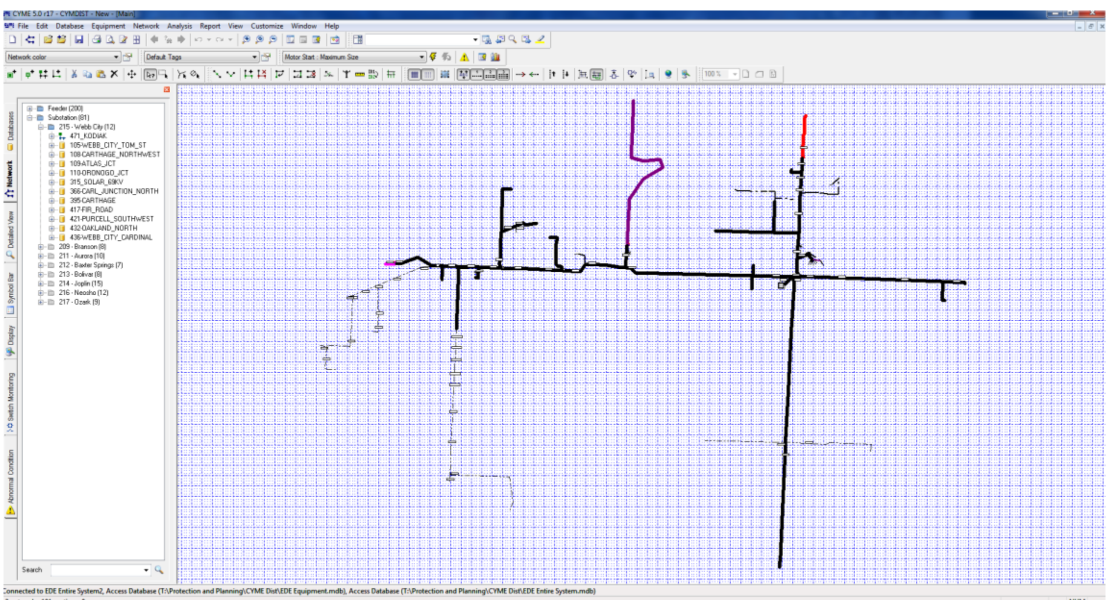

Figure 4.5-3 - CYMDIST Screenshot

CYMDIST is a multipurpose tool primarily used by engineers to analyze load-flow characteristics of distribution feeders. Empire's planning department also provides fault current information to customer's electrical contractors when performing arc-flash studies, a process which requires the use of CYMDIST.

1.1.2.1 Capacity Planning

Substation transformer and distribution circuit loads are collected annually, with the primary sources being monthly metering data and seasonal station checks. This load data is compiled into a database that can be parsed into different seasons, definite dates, specific months, or years' worth of data for analysis. The data is also compared to the maximum capacity available at the service transformer to determine overloads evident in past scenarios or present system configurations. These types of overloads are higher in priority due to the severity and long lead time mitigations available.

Figure 4.5-4 is an example of substation trending over multiple years in the summer seasons.

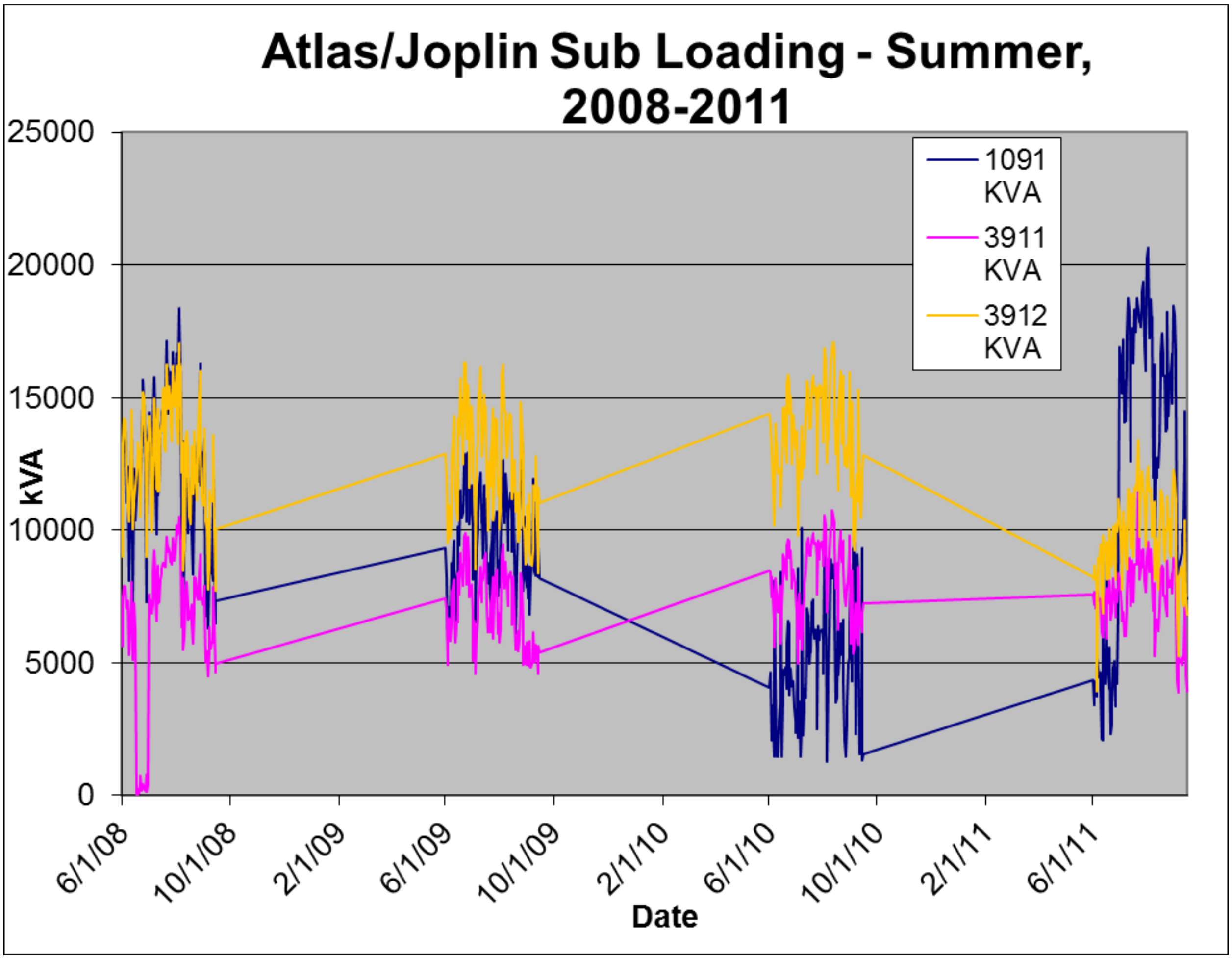

Figure 4.5-4 - Substation Trending Over Multiple Years During Summer Seasons

A screenshot of the Microsoft® Access metering database compiled for seasonal, annual, or definite time interval(s) is shown in *Figure 4.5-5*.

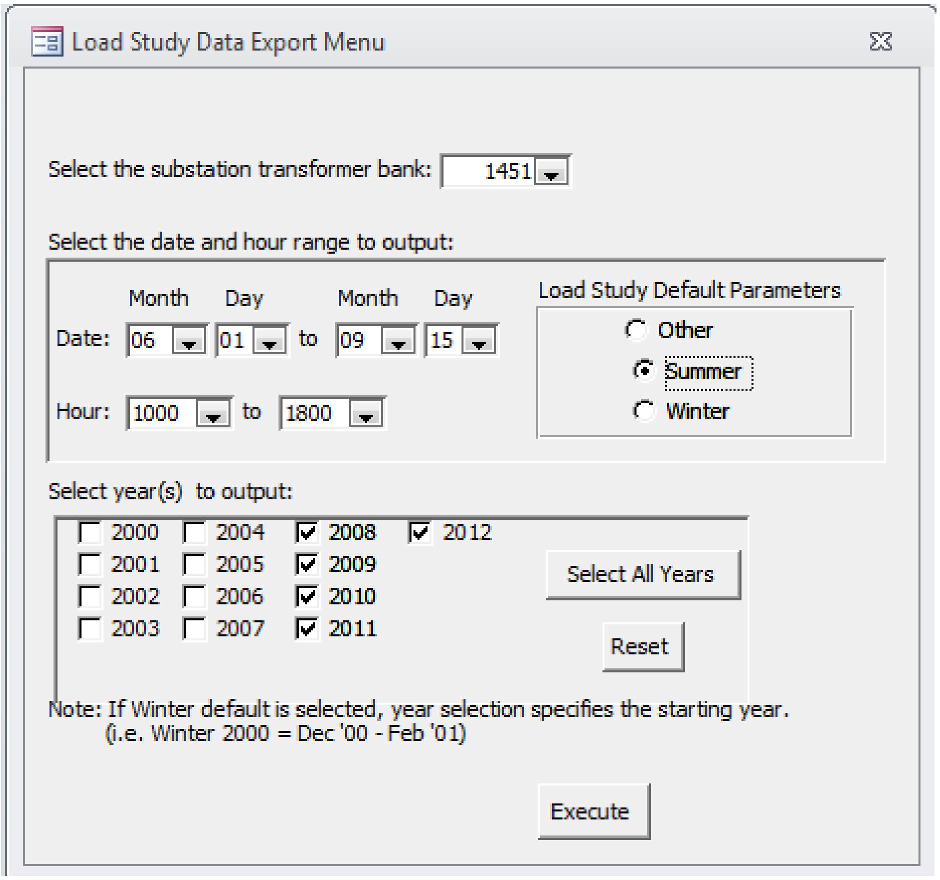

Figure 4.5-5 - Metering Data Compiled For Seasonal, Annual, or Definite Time Interval(s)

1.1.2.2 Contingency Planning

Transmission and distribution system planning includes consideration of contingencies and their impact on the systems as they may change under varying conditions.

1.1.2.2.1 **Distribution Contingency Evaluation**

From distribution studies performed throughout a given year, Empire's planning department determines what switching paths are available during a contingency event. Examples of these types of studies include evaluation of substation transformer loading to determine available capacity present on a substation of interest, splitting trunk lines and their effects on voltage profiles on a given feeder, and phase loading imbalance due to the topography changes made during switching adjustments. These studies allow for the engineering department to make informed decisions on available transfer capabilities on specific feeders. Once weaknesses are identified and analyzed, the resulting system impacts can be ranked against other results for determining capital budget project priority. Ultimately, this ranking, energy efficiency impacts, reliability and customer impact risks, and the project cost are used to determine whether or not a system improvement is implemented. The Empire planning department identifies the weaknesses and provides budgetary estimation and project description in conjunction with Empire Line Design department. It also becomes the responsibility of the planning department to thoroughly communicate the justifications for projects to the vested departments internal to Empire.

1.1.2.2.2 **Transmission Contingency Evaluation**

Empire conducts transmission system performance studies as required by the NERC TPL-001, TPL-002, TPL-003, and TPL-004 standards. These studies are provided as supplements to the SPP TPL Compliance Report. Studies include evaluations of base case, N-1 (meeting the N-1 criteria within the Empire system footprint), multiple contingencies (Type C), and extreme contingency scenarios (Type D), as defined in Table 1 of the NERC Transmission Planning Standards.

1. Base Case - All Facilities In-Service: The studies are conducted on an annual basis incorporating both near-term and long-term planning horizons. The models used in the study process have an initial condition of normal operating

procedures in place, have all projected firm transfers modeled, are performed over a range of forecasted demand levels for selected demand levels, and include existing and planned facilities as well as reactive power resources to ensure that adequate reactive resources are available. Once these studies are conducted, mitigation techniques are ascertained to fulfill the performance requirements of the TPL-001 standard.

2. N-1 - Loss of a Single Element:

   a. The studies are conducted on an annual basis incorporating both near-term and long-term planning horizons. The models used in the study process have an initial condition of normal operating procedures in place, have all projected firm transfers modeled, are performed over a range of forecasted demand levels for selected demand levels, and include existing and planned facilities as well as reactive power resources to ensure that adequate reactive resources are available. Once these studies are conducted, mitigation techniques are ascertained to fulfill the performance requirements of the TPL-002 standard. The power flow models evaluated were created from the SPP 2011 Model Development Working Group (MDWG) B2 Final MOD Base Case series.

   b. The N-1 contingency analysis was run for each of the seasonal models from the 2011 series cases with varying system demands including winter, spring, summer, and fall. Alongside the TPL compliance report's automatically selected contingencies, an internal review of all N-1 contingencies within the Empire footprint was performed. The rationale used in choosing the contingencies studied included all single elements as defined in SPP Criteria 12 within the Empire footprint along with the effects of outaged tie lines with neighboring entities.

3. Multiple Contingencies - Loss of Two or More Elements:

   a. The studies are conducted on an annual basis incorporating both near-term and long-term planning horizons. The models used in the study process have an initial condition of normal operating procedures in place, have all projected firm transfers modeled, are performed over a range of forecasted demand levels for selected demand levels, and include existing and planned facilities as well as reactive power resources to ensure that adequate reactive resources are available. The power flow models evaluated were created from the SPP 2011 MDWG B2 Final MOD Base Case series. The multiple contingency analyses were run for each of the seasonal models from the 2011 series case with varying system demands including winter, spring, summer, and fall. Alongside the TPL compliance report's automatically selected contingencies, an internal review of Type C contingencies within the Empire footprint was performed. Once these studies are conducted, mitigation techniques are ascertained to fulfill the performance requirements of the TPL-003 standard.

b. The conditions evaluated which conform to Type C contingencies include loss of two or more elements (normal clearing, manual system adjustments between events), bus section faults, double circuit tower lines, and breaker to breaker sectional outages. The resultant thermal and voltage overloads were then evaluated in an effort to mitigate wherever possible with minimal loss of demand and curtailment of firm transfers. In satisfying the requirements of TPL-003, Empire does not employ a rating rational on the severity of specific contingency scenarios. Empire reviews the aforementioned applicable contingencies as defined in Table 1, Type C. In an effort to encompass the worst case scenario outages, the bus outages were included in the Type C contingencies but are also applicable to Type D contingencies. Bus section outages have been shown to be the most effectual outages on the Empire system, due to the number of outaged elements associated with individual simulations. The outages which involve single-line-to-ground or three-phase faults were not evaluated for stability purposes. The rationale for this omission hinged on three factors: no substantial system changes directly relating to stability were made to the Empire system, a previous stability study (the 2006 System Facilities Study) showed no Empire stability-related issues, and no stability issues were evident in the previous SPP TPL compliance reports.

4. Extreme Event (Multiple Elements) Contingency: The studies are conducted on an annual basis incorporating both near-term and long-term planning horizons. The models used in the study process have an initial condition of normal operating procedures in place, have all projected firm transfers modeled, are performed over a range of forecasted demand levels for selected demand levels, and include existing and planned facilities as well as reactive power resources to ensure that adequate reactive resources are available. Once these studies are conducted, mitigation techniques are ascertained to fulfill the performance requirements of the TPL-004 standard. The power flow models evaluated were created from the SPP 2011 MDWG B2 Final MOD Base Case series. The multiple contingency analyses were run for each of the seasonal models from the 2011 series case with varying system demands including winter, spring, summer, and fall. Alongside the TPL compliance report's automatically selected contingencies, an internal review using the rationale of all applicable contingencies which conform to Table 1, Type D within the Empire footprint was performed. These include loss of a tower line with three or more circuits, all circuits on common right-of-way, substation (one voltage level plus transformer), and the loss of all generating units at a station. The resultant thermal and voltage overloads are then evaluated in an effort to

mitigate wherever possible, with minimal loss of demand and curtailment of firm transfers. In satisfying the requirements of TPL-004, Empire does not employ a rating rational on the severity of specific contingency scenarios, but rather reviews contingencies applicable to Empire as defined in Table 1, Type D. Contingencies that are not applicable to Empire's footprint were not evaluated including Type D contingencies involving special protection systems, load centers, and switching stations.

1.1.2.2.3 **Worst Performing Circuit Analysis**

To improve the performance of the circuits, Empire adopted a corrective action plan that includes the following activities:

1. Empire employees perform a "walk-through" of the worst performing circuit, collecting engineering data to support the following coordination study and sectionalizing program. Items are noted and corrected as part of the corrective action plan. Upon walk-through completion, a coordination study of the circuit occurs. The coordination study evaluates protective equipment settings and application to ensure each protective device properly operates with other upstream and downstream protective equipment. Additional sectionalizing is then added to the circuit to reduce the number of customers experiencing an outage, in the event an outage occurs, thus increasing reliability to other customers on the circuit. Faulted circuit indicators are also added to the circuit to reduce restoration time and shorten customer outage duration. In addition to the coordination study and sectionalizing program, any vegetation-related issues identified are scheduled to be cleared for each circuit.

1.2 Assessment 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;

Empire's is required to meet the interconnection needs of transmission customers for connection to, and use of, the Empire transmission system. The Federal Energy Regulatory Commission (FERC)-approved transmission tariffs provide procedures for detailed transmission studies and interconnection estimates for connecting to and using Empire's transmission system. Empire's planning department provides a range of transmission costs for various sites of interest on defined projects and identifies potential transmission limitations with the inclusion of projects of interest. Any Empire generation resource addition that would impact transmission level flows is required to proceed through the Southwest Power Pool (SPP) Generation Interconnection (GI) process before it could be interconnected to the transmission system. Every resource addition would also have to be included in the SPP Aggregate Facility Study (AFS) process to obtain firm transmission service for delivery of generation to load. The SPP Definitive Interconnection Study for Generation Interconnection Requests (DISIS-2012-001) is provided for reference in Appendix 4.5A.

An example of this process is the addition of Empire's Riverton Unit 12 with the inclusion of future expansion to a combined cycle configuration. Once this additional resource had been submitted for study in the GI and AFS processes the resultant upgrades were identified and evaluated for feasibility and cost effectiveness.

This process is further illustrated in *Figure 4.5-6*, which provides approximate Generation Interconnection data for wind projects taken from the SPP Generation Interconnect Queue on January 5, 2011. Note that no wind projects were planned to be located within Empire's electric service territory in southwest Missouri. However, due to the number of projects in play, the SPP AFS process is rigorous and robust, developing specific impacts of the individual and aggregate projects on the SPP system and on those of its members.

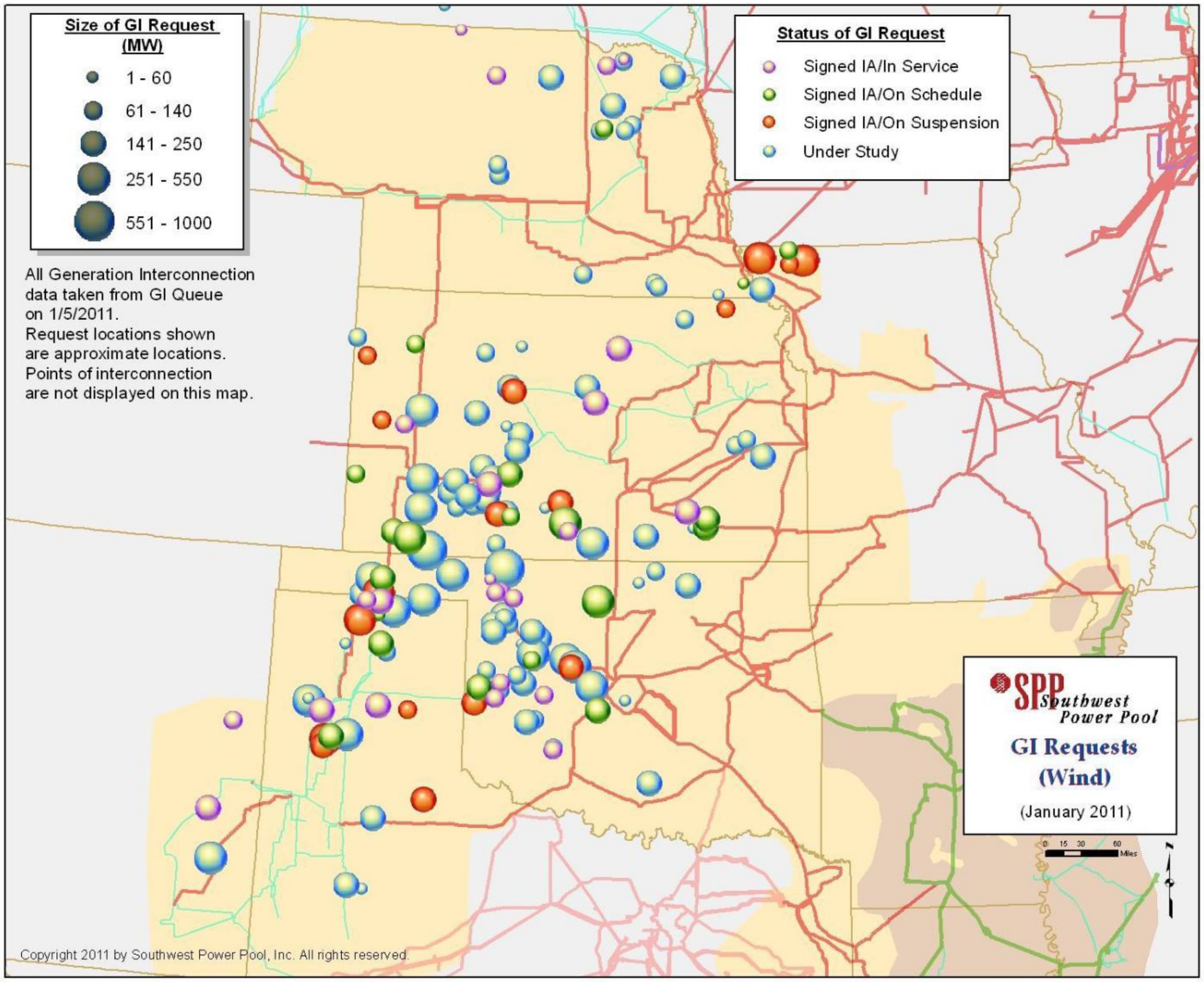

Figure 4.5-6 - SPP 2011 Generation Interconnection Requests for Wind Projects[1]

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

[1] Source: "RTO Renewable Generation Dispatch: How high can we go?" Presented by Bruce Rew, Vice President Operation, SPP at the Rocky Mountain Electric League's Spring 2013 Management, Engineering and Operations Conference in Vail, Colorado on May 21, 2013, at page 10.

All Empire transmission planning is performed in conjunction with the SPP, the Regional Transmission Organization (RTO) to which Empire belongs. Empire's affiliation with SPP began during World War II when the SPP was initially formed. The FERC empowers RTOs to assure power supply reliability, transmission infrastructure adequacy, and competitive wholesale electricity prices through the North American Electric Reliability Corporation (NERC). In turn, SPP oversees enforcement and development of NERC reliability standards within its footprint which spans across nine states. Empire fully participates in SPP's regional transmission expansion plan processes. SPP conducted two recent expansion plan processes: the Balanced Portfolio (June 2009) and the Priority Projects (April 2010). Regardless of whether or not Empire adds supply resources or contracts for sales, the unique and specific costs of the Balanced Portfolio and Priority Projects will be allocated throughout SPP. Therefore, no costs for Empire's allocation of the costs for the Balanced Portfolio and the Priority Projects have been included in the analyses of preliminary supply-side resource options in this plan.

The Balanced Portfolio is the SPP strategic initiative to develop economic-based regional transmission upgrades benefiting the SPP region while allocating the cost of the upgrades across the utilities in the region. Balanced Portfolio projects have included 345-kV transmission upgrades to obtain potential savings that exceed the costs of the projects. Such upgrades are intended to reduce congestion on the SPP transmission system, and thereby reduce generation production costs. Other benefits result including increased reliability and lower required reserve margins, deferment of other reliability upgrades, and environmental benefits from more efficient operation of generating assets and increased renewable resource production. SPP's analysis of the Balanced Portfolio concluded that these projects would provide an average benefit of $1.66/month per customer for a corresponding cost of $0.88/month per customer. Seven transmission projects for a total initial estimated engineering and construction cost of approximately $692 million were included in the Balanced Portfolio, as shown in *Figure 4.5-7*.

Figure 4.5-7 - SPP Approved 2009 Balanced Portfolio Transmission Projects[2]

The SPP Balanced Portfolio Report is provided in Appendix 4.5B for further reference.

The purpose of SPP's Priority Projects plan was to identify, evaluate, and recommend transmission projects that could improve regional production costs, reduce grid congestion, enable large-scale renewable resources (primarily wind), improve the GI and AFS processes, and better integrate SPP's east and west regions. Six transmission projects with an approximate total cost of $1.1 billion were recommended for construction in the Priority Projects process providing a variety of benefits to the region. These Priority Projects will reduce transmission congestion, while improving the AFS process by creating additional transfer capability, and also increase the ability to transfer power in an eastward direction for the majority of the transmission paths between SPP's western and eastern areas to facilitate wind power.

The April 27, 2010 SPP Priority Projects Phase II Final Report is provided in Appendix 4.5C.

[2] Source: web site http://www.spp.org/section.asp?pageID=120 down loaded June 8, 2013.

The current study in progress at SPP is the Integrated Transmission Plan (ITP). There are three subsets of this particular study: ITP 20-Year (ITP20), ITP 10-Year (ITP10), and ITP Near-Term (ITPNT). Empire is an active participant in each of these studies and maintains a voting membership in each of the respective working groups.

The ITP is a three-year study process which assesses the SPP region's transmission needs in the long- and near-term with the intention of creating a cost-effective, flexible, and robust transmission network that will improve access to the region's diverse generating resources. Along with the recently approved highway/byway cost allocation methodology, the ITP process as embodied in the new SPP Attachment O, approved by the FERC in July 2010, promotes transmission investment that will meet reliability, economic, and public policy needs. This report documents analysis of the ITP process which focused on the 20-year horizon with an objective of planning for SPP's long-term regional needs. ITP development was driven by the Synergistic Planning Project Team (SPPT), which was created by the SPP Board of Directors to address gaps and conflicts in all of SPP's transmission planning processes including Generation Interconnection and transmission service; to develop a holistic, proactive approach to planning that optimizes individual processes; and to position SPP to respond to national energy priorities. The ITP is based on the SPPT's planning principles which emphasize the need to develop a transmission backbone large enough in both scale and geography to provide flexibility to meet SPP's future needs.

This is the first ITP looking into the future 20 years as required by Open Access Transmission Tariff (OATT) Attachment O, Section III - 3. It is an expansion of the annual SPP Transmission Plan (STEP), which is the 10-year transmission expansion plan in place since 2006. SPP has had two previous EHV plans which similarly provide a look into the future that help to form the near-term plans. Projects identified in the ITP20 provide benefits to the region across multiple futures, and create flexibility for SPP to meet future needs. The ITP effort has been driven by numerous interactions with stakeholders and with significant support from the Economic Studies Work Group (ESWG) and Transmission Working Group (TWG) (which Empire participates and maintains voting membership in both). This plan differs from the earlier EHV plans in the level of detail and effort that has gone into its preparation.

The second phase of the ITP study process included the first IITP10 and ITPNT assessments performed under the requirements of OATT Attachment O, Section III. The study process for this ITP10 utilized a diverse array of power system and economic analysis tools to evaluate the need for 100-kV and above facility projects that satisfy needs such as:

1. Resolving potential criteria violations.
2. Mitigating known or foreseen congestion.
3. Improving access to markets.
4. Staging transmission expansion.
5. Improving interconnections.

The recommended portfolio included projects ranging from comprehensive regional solutions to local reliability upgrades to address the expected reliability, economic, and policy needs of the studied 10-year horizon. Two distinct futures were considered to account for possible variations in system conditions over the assessment's 10-year horizon.

The most recent iteration of the ITPNT was approved by the SPP Board of Directors in January of 2012. This report is provided in Appendix 4.5D for reference. The ITPNT analyzes the SPP region's immediate transmission needs. The goals of the ITPNT are to not only preserve grid reliability, in compliance with NERC reliability standards and individual transmission owner planning requirements, but to also efficiently bridge SPP's 10-year and 20-year plans that meet public policy objectives and provide access to more economic energy sources. The ITPNT assesses:

1. Regional upgrades required to maintain reliability in accordance with the NERC reliability standards and SPP criteria in the near-term horizon.

2. Zonal upgrades required to maintain reliability in accordance with more stringent individual transmission owner planning criteria in the near-term horizon.

3. Coordinated projects with neighboring transmission providers.

Empire also participates with non-SPP members (e.g., Associated Electric Cooperative, Incorporated (AECI)) in attempts to explore and examine potential mutually beneficial projects. The most recent example is Empire's participation in the AECI-SPP Joint Study. This is a recurring study that involves impacted SPP members in the southeastern portion of the SPP footprint along with the neighboring seams companies. The scope of the studies involve identifying forecasted issues on both seams parties' footprints and working together to study proposed projects to acquire mutually beneficial results. This type of study allows for conversation to flow between SPP members and non-members so that interconnections, mitigation techniques, and cost sharing projects can be vetted on both sides of ownership so as not to put the entire burden on one entity but rather pair common goals with collective and more impactful results. Empire not only provides possible projects for study, but also internally studies presented projects to determine whether a proposed project could mutually benefit Empire and AECI exclusive of other southeastern SPP members' lack of interest or benefit.

1.4 Assessment of Transmission or Distribution Improvements with Respect to Cost Effectiveness of 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.

1.5 Capacitor Control Upgrades

Empire has examined and determined needed upgrades for the automation of capacitor bank controls. Previously, simple time and/or temperature controls were installed for capacitor bank control. Upgraded capacitor controls, which include parameters of time, date, temperature, voltage, and VAr (additional option), are installed on all new installations of cap banks. Present controls are replaced on an as-needed basis as original controls fail or become inoperable or operate incorrectly. The power factor at the substation is also improved by the automated addition and removal of capacitance when demand necessitates. This immediate response to load profile changes allows the distribution system to be manipulated to optimize voltage profile along a given feeder.

1.5.2 Advanced Utilization of Regulator Controls

In reviewing possible candidates for the installation of regulators on a distribution feeder, the Empire planning department makes use of advanced regulator controls in an effort to optimize the voltage profile alongside the use/installation of capacitor banks with advanced controls. Empire's regulator controls have multiple functionalities and parameters that can be tailored to the feeder specifications. Empire evaluates feeders' voltage profiles and programs as such to attain the most effectual response from the regulator. Empire does not simply raise/buck voltage as a response to demand but also implements the proper bandwidths, timer delays so as not to over-wear contacts within the regulators, and the associated compensative settings (impedance and reactance) for the needed end-of-line response. In utilizing regulator controls to this level, Empire gains multiple benefits (i.e., MW demand reduction from voltage control, substation voltage regulation/flexibility, load tap changer flexibility and manipulative bandwidth, VAr flexibility allowing reflection onto the transmission system, etc.) from not only the regulator itself but also the Empire distribution system as a whole.

1.5.3 **Advanced Relaying Utilization**

In an effort to modernize Empire's distribution and transmission systems, all proposed, merited capital projects are reviewed during Empire's construction budget process to identify gains that could be realized with the inclusion of advanced relaying. When presented with a project, Empire's planning and protection department alongside the substation construction department reviews the scope of work and attempts to identify upgrades needed which would most benefit the customers served off the identified feeders and/or substations. One example would be the auto transformer failure at Empire's Powersite No. 312 in the spring of 2012. Empire's planning and protection department along with the substation construction department were able to identify electromechanical relaying that had limited availability of replacement components, no way of recording event data, non-redundant protection, inadequate overlapping zones of protection, and additional exposure to high value equipment which could drastically affect SAIDI and SAIFI for the area transmission systems. Due to the extent of the work to replace an auto transformer, the relaying was deemed as a prime candidate for upgrade. The job was engineered to not only bring the relaying up to adequate Empire protective specifications, but also to allow for future betterment of the protection scheme at the substation of interest. Empire saw a need and attempted to gain synergy while undertaking a common site task by expanding the original project scope so as to better the reliability for its customers. The gains to be realized once the project has been completed include adequate fault recording for root cause analysis in future events, overlapping zones of protection for the newly positioned auto transformer, and reduction of exposure to out of zone events as related to the auto transformer.

An example on the distribution level is the inclusion of microprocessor relaying in all new feeder breakers. Empire also replaces electromechanical relaying with microprocessor relays as breakers fail or interrupting capabilities are surpassed. Alongside replacement of breakers, each new substations that Empire constructs will be equipped with multiple microprocessor relays so as to better coordinate with downstream protective devices, expand fault data recording, aid in root cause analysis, expansion of load data profiling, allow for over lapping zones of protection, enable bus differential relaying for additional protection capabilities, etc. By making use of microprocessor relaying, much more additional information can be readily reviewed after an event has occurred to adjust, evolve, and streamline the protective schemes to eliminate prolonged customer outages.

1.5.4 **Utilization of Regulator Controls**

Empire utilizes advanced controls in the voltage regulation of its distribution system. These controls are microprocessor driven and allow for acute adjustments to be made on a given feeder. Voltage regulation lessens the infrastructure to be installed due to the ability to raise or lower the voltage profile along a feeder experiencing high or lightened loads. By way of raising the voltage, the current demand is lowered on a given section of primary conductor. Lowering the current to within allowable ampacity ratings, said section of conductor would not require a reconductor, rather offset the cost of construction. Although voltage regulation is not a new concept to the power industry, the combined use of voltage regulation alongside capacitor controls and load tap changers can offset construction costs if these controls are operated in conjunction with each respective controller's effects on the given feeder. Empire conducts such a review if a voltage issue is presented. Empire reviews the lowest cost, highest efficacy solution for a given distribution system by using the aforementioned distribution modeling software (CYMDIST), microprocessor controls, and evaluation of the entire feeder as a system.

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).

2.1 Avoided Transmission Capacity Cost

The SPP AFS process encompasses the petition of transmission service and the associated impacts on the existing transmission infrastructure or planned projects meeting specified interconnection agreements and/or having been issued a Notice To Construct (NTC) by SPP during the appropriate study process. All generation requests must be vetted through the SPP AFS process to obtain firm transmission service for delivery of generation to load. In doing so, Empire is able to evaluate the impacts either purchasing generation, adding generation onsite, adding generation offsite, or other applicable generation resource impacts upon the SPP transmission system through the multiple iterative processes of the AFS. As the proposed generation resources profiles are updated in the applicable study, Empire evaluates the most cost effective means to address their needed generation resources to meet forecasted load demand. Thus, the AFS study process reveals the transmission component of avoided demand cost.

The AFS study process is dynamic in nature. Locational differences of the requested resources, the available transmission in the immediate area of the resource, and the competing resources requests each affect the resultant cost of any given generation resource request. As competing requests are vetted by their respective companies, requests are withdrawn from the applicable AFS study. This again changes the AFS study portfolio. In the most recent AFS, Empire was able to determine its respective avoided transmission, avoided costs by averaging past years' AFS Engineering and Construction (E&C) costs as compared to the requested MW resources. The total costs were divided by the summation of requested resources to determine an averaged cost per kilowatt value. The values and the associated studied years are shown in *Table 4.5-4*.

Study Year	Total E&C Cost(s) Weighted to 2012 $'s	MW's in study	2012 $/kW
2005	$56,779,953	751	$76
2006	$304,732,888	1,488	$205
2007	$36,504,259	1,335	$27
2008	$69,230,795	3,336	$21
2009	$37,755,353	2,777	$14
2010	$111,978,371	2,424	$46
2011	$678,153,914	3,936	$172
Totals	$1,295,135,534	16,047	$80.71

Table 4.5-4 - Comparison of AFS Results

Thus the extrapolated cost per kilowatt for each subsequent year is shown in *Table 4.5-5:*

No.	Year	$/kW-Year	Levelized Cost $/kW-Year
1	2012	$80.71	$8.64
2	2013	$82.73	$8.86
3	2014	$84.79	$9.08
4	2015	$86.91	$9.31
5	2016	$89.09	$9.54
6	2017	$91.31	$9.78
7	2018	$93.60	$10.02
8	2019	$95.94	$10.27
9	2020	$98.34	$10.53
10	2021	$100.79	$10.80
11	2022	$103.31	$11.06
12	2023	$105.90	$11.34
13	2024	$108.54	$11.63
14	2025	$111.26	$11.92
15	2026	$114.04	$12.21
16	2027	$116.89	$12.52
17	2028	$119.81	$12.83
18	2029	$122.81	$13.15
19	2030	$125.88	$13.48
20	2031	$129.03	$13.82
21	2032	$132.25	$14.16

Table 4.5-5 - Total Annual AFS E&C Costs as Transmission - Avoided Demand Costs

The dynamic nature of the transmission costs is clearly evident. Each year's requests have differing impacts on the transmission service costs.

SECTION 3 ANALYSIS OF TRANSMISSION NETWORK PERTINENT 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;

Empire's participation with SPP was previously addressed in Section 1.3 regarding assessment of transmission upgrades for power purchases. Empire also utilizes the SPP ITP process to assess the need for, cost of, 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 along with its SPP members and affiliates.

The SPP ITP process is used to determine transmission requirements for maintaining electric reliability and for providing both near- and long-term economic benefits to SPP members and affiliates. The RTO region includes all or parts of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. The SPP ITP process identifies transmission expansion projects and prioritizes their schedules in order to maintain a reliable and cost-effective transmission network with improved access to SPP's diverse resources including wind energy. Wind energy development in Oklahoma, Kansas, Nebraska, and Texas has fluctuated in recent years with variations in federal subsidization, but has dominated new generating capacity additions in SPP for several years.

The SPP ITP process is an iterative, multiple-horizon transmission planning process that has improved transmission planning across the SPP region. By integrating the transmission planning process across member utilities in eight contiguous states, the SPP promotes more rigorous and complete planning throughout a large area to improve the reliability of each utility and the SPP as a whole. The result of this integrated planning process is the development of lowest-cost transmission solutions to anticipate and respond to constantly changing loads, environmental and regulatory requirements, and grid anatomy, while meeting evolving reliability criteria.

The current ITP process includes ITP20, ITP10, ITPNT assessments of transmission requirements to meet load growth and other potential developments. The initial ITP20 process examined high-voltage transmission needs at voltages of 345-kV and above, including the state-by-state requirements for renewable energy over time. ITP20 evaluated the potential impacts of a 20-percent federal renewable energy standard (RES), and a carbon tax. ITP20 projected renewable energy generation of 10.6 GW without a federal RES, and 16.5 GW with a federal RES. Implementation of ITP20 results was estimated in 2011 to cost $1.8 billion for construction of 1,494 miles of 345-kV lines and installation of 11 345-kV step-down transformers.

A value-based planning approach is used for the ITP10 assessment to analyze the transmission system over a 10-year horizon. In the ITP10 process, economic and reliability analyses develop solutions for issues identified on the system for voltages of 69-kV and above as well as such issues identified in the ITP20 that would occur within the ITP10 portion. The ITP10 process included state renewable energy targets and gaged the impact on transmission requirements for a 20-percent federal RES: 10.0 GW of renewable generation without a federal RES versus 14.0 GW of renewable generation with a federal RES. The recommended ITP10 portfolio consisted of projects for potential reliability, economy, and/or policy requirements with an estimated total E&C cost of $1.5 billion in 2012. Economics-driven projects included in this total had an estimated E&C cost of $206 million, with net present value revenue requirements of $302 million, but were predicted to generate net benefits of approximately $596 million over the life of the projects for the 10 GW wind capacity scenario. These projects are needed beginning in 2014 and continue through 2022.

The near-term assessment will identify more immediate potential problems using NERC reliability standards, SPP criteria, and local planning criteria. Reliability upgrades at all transmission voltages are developed to address both regional reliability needs and identify necessary reliability upgrades for approval and construction. SPP performed reliability analyses in 2011 through 2012 that identified potential bulk power system problems and provided these results to transmission owners and stakeholders to develop solutions. Transmission options from other SPP studies, including the aggregate study and Generation Interconnection processes were examined for potential solutions. SPP staff identified and presented their recommended solutions for potential reliability violations during planning summits for member and stakeholder review. The result was a list of solutions necessary at 69-kV and above to ensure the reliability in the SPP region in the near term. E&C cost estimates for the needed reliability projects totaled $251 million for the years 2012 to 2017 in addition to previously (SPP) approved upgrades, not including the $190 million (E&C) in upgrades with active Notification to Construct (NTC) that were to be withdrawn.

Empire is very active in the interaction between SPP and its associated members. Empire participates by way of multiple working groups and various task forces. The following *Table 4.5-6* is a list of working groups/committees and task forces in which Empire participates.

SPP Stakeholder Committee/Task Force (Report to)	Position Type Voting/Monitoring
Members Committee (BOD)	Monitoring
Human Resources (BOD)	Voting - TO
Strategic Planning Committee (BOD)	Voting - TO
SPC Order 1000 Task Force	Monitoring
Membership (all members)	Voting - Empire
Finance Committee (BOD)	Monitoring
Governance Committee (BOD)	Monitoring
Market and Operating Policy Committee (full membership)	Voting - Empire
Transmission Working Group (MOPC)	Voting - Empire
Seams Steering Committee	Voting - VC
Seams Order 1000 Task Force	Voting
Model Development Working Group, reports to TWG	Voting, Vice Chair - Empire
Economic Studies Working Group reports to MOPC (new)	Voting -Empire
Metrics Task Force (Reports to ESWG)	Voting -Empire
Business Practices Working Group (MOPC)	Voting - Empire
Consolidated Balancing Authority Steering Committee - MOPC	Voting - Empire
CBA Technical Task Force	Voting - Empire
Members Compliance Group (ad hoc)	Monitoring
Regional Tariff Working Group (MOPC)	Voting - Empire
Market Working Group (MOPC)	Voting - Empire
Settlements Users Group	Monitor
Project Cost Working Group	Monitor
Change Working Group	Voting - Empire
Generation Working Group (MOPC)	Voting - Empire
Operations Reliability Working Group (MOPC)	Voting - Empire
Operations Training Working Group (MOPC)	Monitoring
Critical Infra-structure Protection Group - Cyber Security (MOPC)	Voting - Empire
System Protection and Control Working Group (MOPC)	Monitoring
SPP Regional State Committee	Monitoring
Cost Allocation Working Group (RSC)	Monitoring
Regional Cost Allocation (RCA) review task force	Voting - Empire
Regional Entity Trustees (RE)	Monitoring
FERC Jurisdictional TO Coalition (Informal)	Monitoring
ERSC (Plum Point-MISO)	Monitoring
MISO Stakeholder Meetings	Monitoring

Table 4.5-6 - Empire's SPP Participation

The following *Table 4.5.7* provides the Empire management and staff individuals participating in the various committees, studies, and groups at SPP.

SPP Stakeholder Committee / Task Force (Report to)	**Empire Representative Existing**
Members Committee (BOD)	Palmer/Warren
Human Resources (BOD)	Palmer
Strategic Planning Committee (BOD)	Palmer
SPC Order 1000 Task Force	Warren
Membership(all members)	Palmer
Finance Committee (BOD)	Delano
Credit Practices Working Group	Ellis
Oversight Committee	
Governance Committee (BOD)	Palmer/Warren
Market and Operating Policy Committee (full membership)	Warren
Transmission Working Group (MOPC)	Morris
Seams Steering Committee	Warren
Seams Order 1000 Task Force	Warren
Model Development Working Group, reports to TWG	Morris
Economic Studies Working Group reports to MOPC (new)	Sweet
Metrics Task Force(Reports to ESWG)	Sweet
Business Practices Working Group(MOPC)	McCord
Consolidated Balancing Authority Steering Committee - MOPC	McCord/Meyer
CBA Technical Task Force	Pham
Members Compliance Group (ad hoc)	Meyer
Regional Tariff Working Group(MOPC)	Warren
Market Working Group(MOPC)	McCord
Settlements Users Group	Tackett
Project Cost Working Group	
Change Working Group	Depratt
Generation Working Group (MOPC)	Houston
Operations Reliability Working Group(MOPC)	Pham
Operations Training Working Group(MOPC)	Pham
Critical Infra-structure Protection Group - Cyber Security (MOPC)	Crayne
System Protection and Control Working Group (MOPC)	Oswald/Morris
SPP Regional State Committee	Warren/Palmer
Cost Allocation Working Group(RSC)	Warren
Regional Cost Allocation (RCA) review task force	Warren
Regional Entity Trustees(RE)	Meyer/Warren

Table 4.5-7 - Current Empire Staff Assignments at SPP

3.1.2 **Transmission Assessment for Advance Technologies**

2. Assessment of transmission upgrades to incorporate advanced technologies;

Empire incorporates three main advanced technologies in its transmission system: All-dielectric self-supporting (ADSS) cable and/or optical ground wire (OPGW), microprocessor relaying, and automatic throw-over switching schemes on the 69-kV transmission system(s).

Empire currently employs the use of ADSS cable and has previously employed the use of 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 144 single-mode fibers per shield wire, whereas ADSS incorporates 144 single-mode fibers allowing for not only presently needed communication paths for protection schemes but also allows for future implementation of further SCADA installation(s) and communication paths for backup/redundant relaying.

Empire utilizes microprocessor relaying for all new relaying installations. Substantial gains are found in the implementation of microprocessor relaying with respect to root cause analysis of fault events, as well as in protective coordination of transmission elements. With the use of microprocessor relaying, event recordings are able to be reviewed for possible misoperation as well as duplication of fault events to determine possible common fault locations. In conjunction with the aforementioned ADSS or OPGW, differential relaying on transmission elements are able to be implemented which result in a much more robust and increased speed of relay operation.

Empire has also implemented automatic throw-over switching schemes on the 69-kV transmission system(s) in attempts to reduce SAIDI and SAIFI. Due to their location on the transmission system, load taps on the 69-kV transmission system are dependent on remote relaying operations. If/When the remote relaying opens a transmission line segment, the load tap is de-energized. A solution is an automated throw-over scheme in which either side of the load tap of transmission is opened during a fault condition and tested to determine the faulted section. Once the faulted section is determined, the alternate section is then restored, thereby restoring power to the load tap. Empire incorporates microprocessor relaying in these schemes as well as ADSS cable (when applicable) so as to ensure fast response and robust protection.

3.1.3 **Avoided Transmission Cost Estimate**

3. Estimate of avoided transmission costs;

Avoided transmission costs are discussed in Section 2 at Page 4.5-25. The results of the aforementioned estimation are provided in *Table 4.5-8* for convenience:

Study Year	Total E&C Cost(s) Weighted to 2012 $s	MWs in study	2012 $/kW
2005	$56,779,953	751	$76
2006	$304,732,888	1,488	$205
2007	$36,504,259	1,335	$27
2008	$69,230,795	3,336	$21
2009	$37,755,353	2,777	$14
2010	$111,978,371	2,424	$46
2011	$678,153,914	3,936	$172
Totals	$1,295,135,534	16,047	$80.71

Table 4.5-8 - Comparison of AFS Results

The extrapolated cost per kilowatt for each subsequent year is shown in *Table 4.5-9*:

No.	Year	$/kW-Year	Levelized Cost $/kW-Year
1	2012	$80.71	$8.64
2	2013	$82.73	$8.86
3	2014	$84.79	$9.08
4	2015	$86.91	$9.31
5	2016	$89.09	$9.54
6	2017	$91.31	$9.78
7	2018	$93.60	$10.02
8	2019	$95.94	$10.27
9	2020	$98.34	$10.53
10	2021	$100.79	$10.80
11	2022	$103.31	$11.06
12	2023	$105.90	$11.34
13	2024	$108.54	$11.63
14	2025	$111.26	$11.92
15	2026	$114.04	$12.21
16	2027	$116.89	$12.52
17	2028	$119.81	$12.83
18	2029	$122.81	$13.15
19	2030	$125.88	$13.48
20	2031	$129.03	$13.82
21	2032	$132.25	$14.16

Table 4.5-9 - Total Annual AFS Cost Results as Transmission - Avoided Demand Costs

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;

The SPP OATT requires that a “Rate Impact Analysis” be performed for each ITP per Attachment O, Section III, Subsection 8:

“8) Process to Analyze Transmission Alternatives for each Assessment:

The following shall be performed, at the appropriate time in the respective planning cycle, for the 20-Year Assessment, 10-Year Assessment and Near Term Assessment studies:

e) The analysis described above shall take into consideration the following:

vi) The analysis shall assess the net impact of the transmission plan, developed in accordance with this Attachment O, on a typical residential customer within the SPP Region and on a $/kWh basis.”

The rate impact analysis process required to meet this 2013 ITPNT requirement was developed under the direction of the Regional State Committee in 2010 and 2011 by the Rate Impact Task Force (RITF). The RITF developed a methodology that allocated costs to specific rate classes in each SPP pricing zone.

The first step in this process is to estimate the zonal cost allocation of the Annual Transmission Revenue Requirements (ATRR) for the ITPNT upgrades using the SPP Cost Allocation of ATRR forecast (forecast). The forecast allocated 2013 ITPNT upgrade costs to the SPP pricing zones using the highway/byway ratemaking method. This method allocates costs to the individual zones and to the region based on the individual upgrade’s voltage. Transformer costs were allocated based on the low side voltage. Regional ATRRs are summed and allocated to the zones based on their individual load ration share percentages.

Highway Byway Ratemaking		
Voltage	Regional	Zonal
300 kV and Above	100%	0%
100 kV – 299 kV	33%	67%
Below 100 kV	0%	100%

Figure 4.5-8 - Highway Byway Ratemaking

The following inputs and assumptions were required to generate the forecast:

1. Initial investment of each upgrade.
   a. Total ITPNT investment modeled was $651 Million.
2. Transmission Owner's estimated individual annual carrying charge percent.
   a. SPP Footprint averages ~16.5 percent per year.
3. Voltage level of each upgrade.
4. In-service year of each upgrade.
5. 2.5 percent annual straight-line rate base depreciation.
6. Mid-year in-service convention.

Empire presently does not have any projects identified in the ITPNT. The NTCs previously issued for projects have been submitted for withdrawal and are supported to be withdrawn by SPP transmission planning studies. The associated project NTCs to be withdrawn are in *Table 4.5-10*:

2013 Requested Board Action	PID	UID	Facility Owner	Project Description/Comments
NTC - Withdraw	472	10608	Empire	Reconductor 2.85 miles of 1/0 cu with 556 ACSR
NTC - Withdraw	422	10548	Empire	Reconductor 9.85 miles of 69-kV 1/0 cu between Sub #170 and Sub #345 with 556 ACSR
NTC - Withdraw	422	50348	Empire	Reconductor 3.58 miles of 69-kV 1/0 cu between Sub #345 and Sub #451 with 556 ACSR
NTC - Withdraw	422	50352	Empire	Reconductor 1.55 miles of 69-kV 1/0 cu between Sub #451 and Sub #359 with 556 ACSR
NTC - Withdraw	537	10685	Empire	Build new 6-mile Sub 383 - Monett 5 161-kV line as part of multi-line upgrade
NTC - Withdraw	537	50316	Empire	Build new 1.04-mile 69-kV line from new Monett S. substation to existing 69-kV trunk line
NTC - Withdraw	537	50326	Empire	Install 3 winding transformer connecting Monett 376 161-kV bus to Monett 470 69-kV bus as part of multi-line upgrade
NTC - Withdraw	537	50350	Empire	Build new 0.72-mile 69-kV line (one of double circuit) from new Monett S. substation to existing 69-kV on SW corner of city of Monett
NTC - Withdraw	537	50353	Empire	Build new 1.06-mile 69-kV line (second of double circuit for approx. 0.72 mi, then single circuit for 0.34 mi) from new Monett S. substation to existing 69-kV on south side of city of Monett which will tie/feed radially to substation PUR390.
NTC - Withdraw	677	10891	Empire	Tear down the Riverton - Joplin 59 69-kV line, rebuild as 161-kV from Stateline to outside Joplin 59 substation
NTC - Withdraw	677	10894	Empire	Tear down and rebuild Pillsbury - Reinmiller 69-kV as 161-kV
NTC - Withdraw	677	50322	Empire	Rebuild Joplin 422 - Joplin 59 69-kV as 161-kV
NTC - Withdraw	677	50323	Empire	Rebuild Joplin 422 - Pillsbury 69-kV as 161-kV
NTC - Withdraw	677	50324	Empire	Rebuild Joplin 391 - Gateway 69-kV as 161-kV
NTC - Withdraw	677	50325	Empire	Rebuild Gateway - Joplin 389 69-kV as 161-kV

Table 4.5-10 - Status of Notifications to Construct

The projects encompass four main projects (see column labeled PID (project ID)) and described with their respective construction explanations. With these withdrawals, Empire will have no direct zonal costs assigned due to Empire direct projects. Empire will have costs associated with the other members' zonal and regional proposed projects shown in *Figure 4.5-9* (as taken from the Draft 2013 ITPNT Report). The peak impact year, based on peak ATRR, was shown to be 2019.

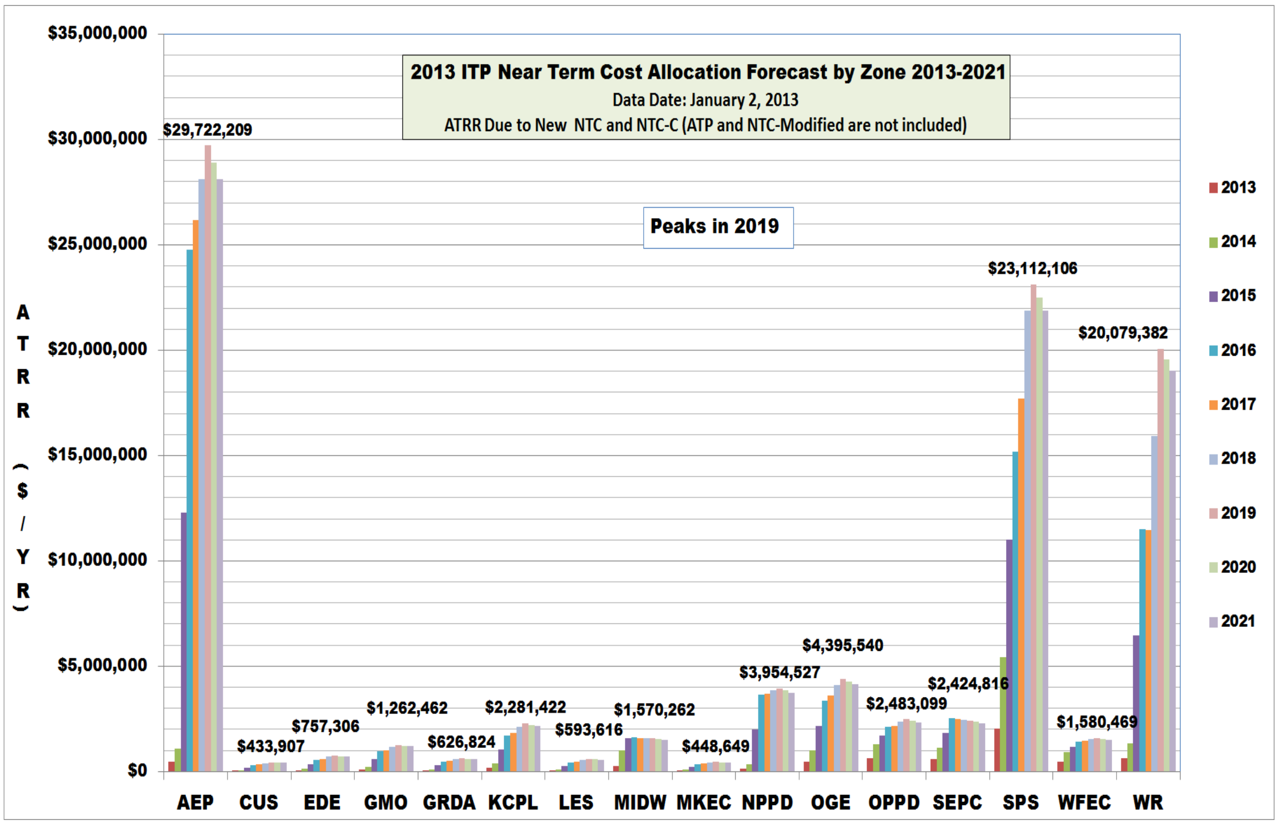

Figure 4.5-9 - Peak Year 2019 Impact of Annual Transmission Revenue Requirements by Pricing Zone

For additional information on estimating ATRR by zone please refer to:

http://www.spp.org/publications/UPDATED%20July%2010%202012%20TEN%20YEARS%20ONLY.zip

The peak year ATRR was then converted to an incremental impact to a typical 1,000-kWh per month to each zone's retail residential electric consumer's monthly electric bill. The rate impacts were determined by multiplying the peak year ATRR by each zone's specific residential and retail allocation percentage(s). The allocated ATRR in 2019 was then divided by the forecast of annual sales in each specific zone in 2019 to determine an incremental rate, based on the ITPNT upgrades. The ATRR cost allocated first to the zone and then to the retail ratepayer in the zone was multiplied by an assumed average consumption of 1,000-kWh per month to determine the final rate impact shown in *Figure 4.5-10* in dollars per month:

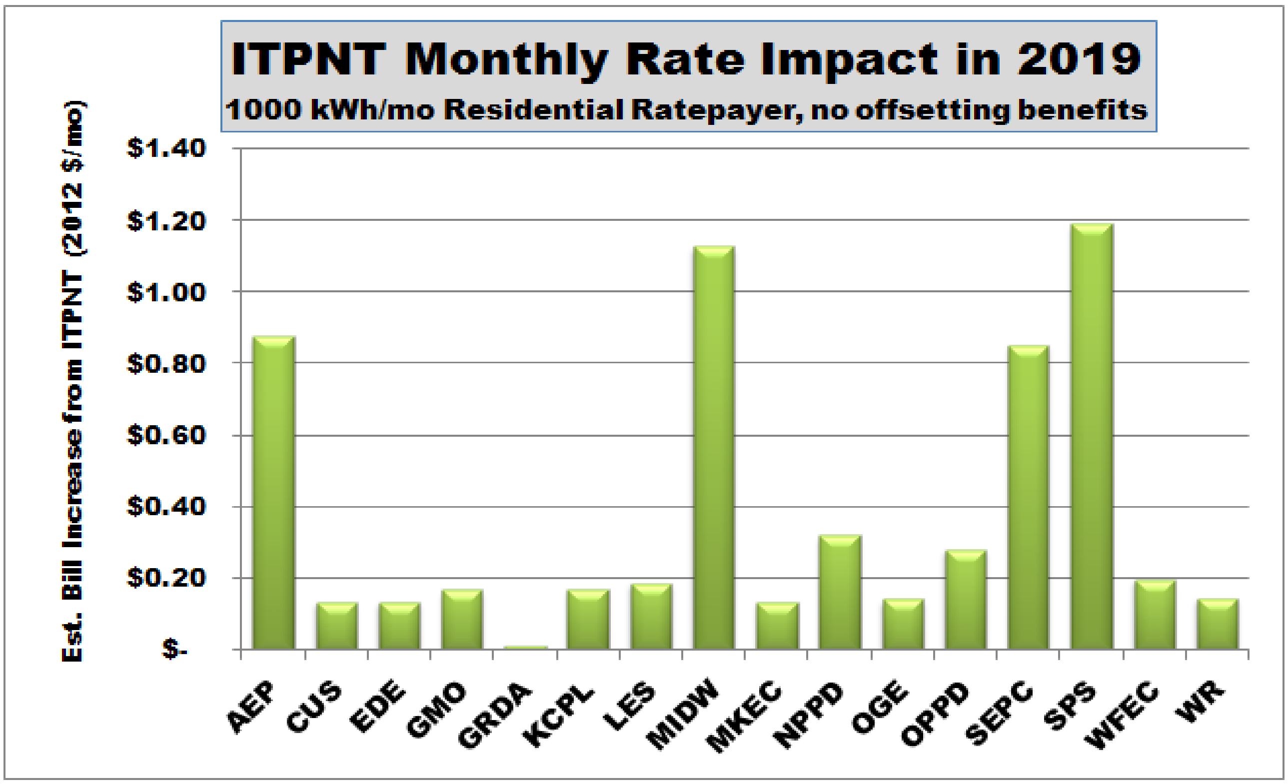

Figure 4.5-10 -2013 ITPNT Monthly Bill Impact to a 1000 kWh / M Residential Customer

These results are shown in 2012 dollars; neither the effect of construction price inflation nor the discounting of future dollars was considered. The effect of depreciation may be seen in the years after 2019.

As shown in *Figure 4.5-11*, the voltage of the near-term reliability upgrades tends to generate costs that will be allocated directly to the zones where the upgrades will be built. These zones also tended to have the highest rate impacts.

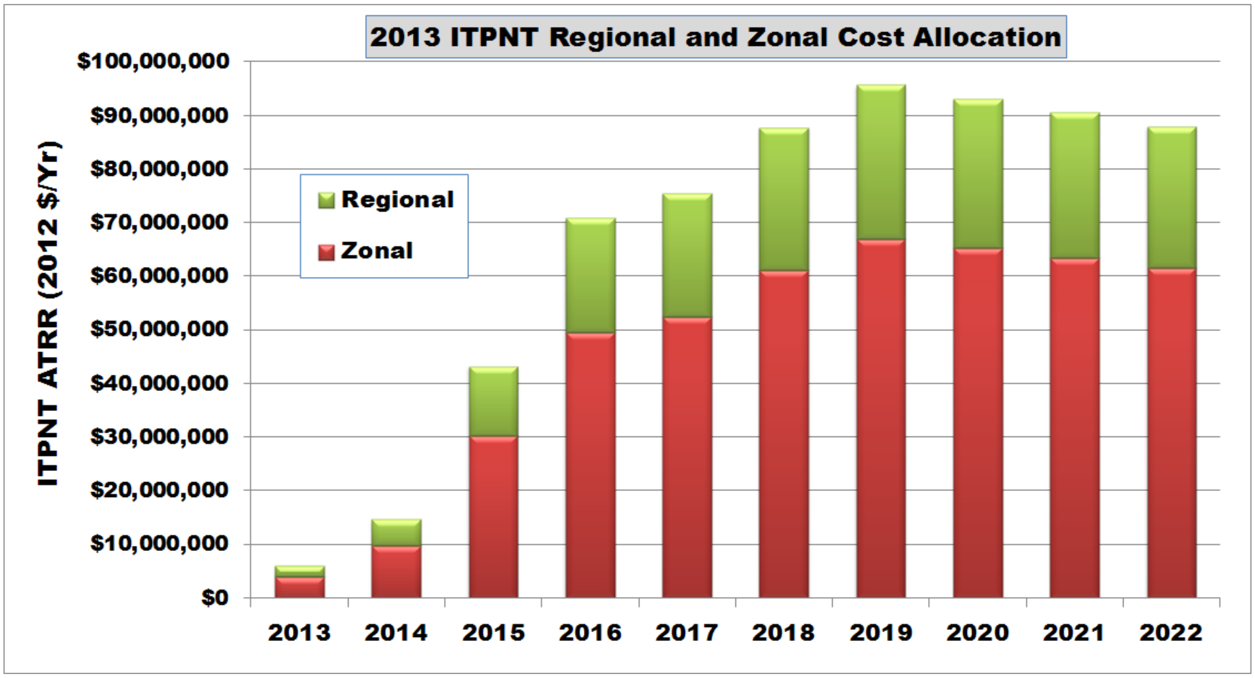

Figure 4.5-11 - 2013 ITPNT Regional and Zonal Cost Allocation

For additional information on how rate impacts are estimated please refer to:

http://www.spp.org/publications/RITF%20Output%20for%20RSC%20Jan%2024%202011%20REV%204.ppt

The rate impacts results shown in this section are incomplete at this time due to one missing cost estimate for which a conceptual estimate is used. Also a minor adjustment made to three other cost estimates, totaling less than $600K, has not been incorporated in these results.

3.1.5 **Revenue Credits Estimate**

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

The revenue credit process for future regional transmission upgrades has not been fully developed by SPP at this time. The balanced portfolio cost allocation coupled with newly designed highway/byway cost allocations and previous iterations of base plan funding remain in flux. SPP has forecasted values that were included in the previous sections as to the projected utility-specific ATRR are repeated in *Figure 4.5-12*, for convenience.

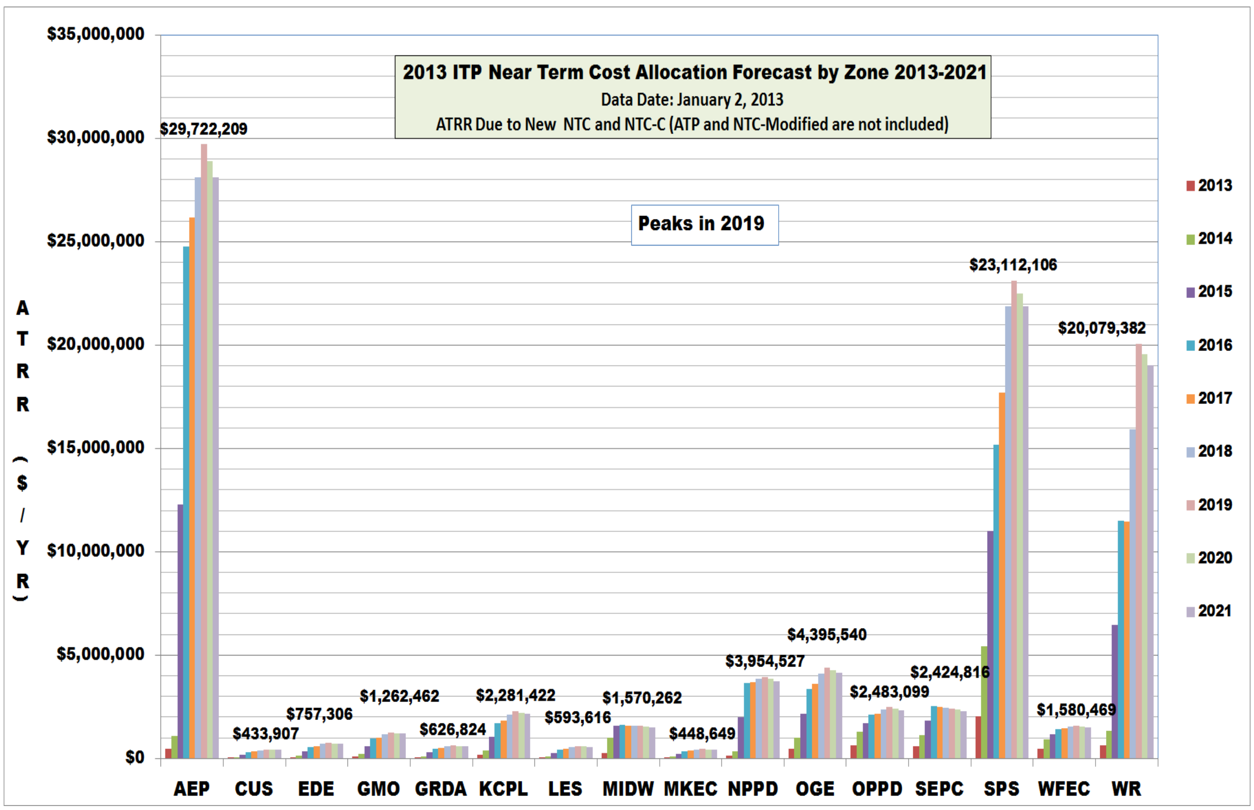

Figure 4.5-12 - 2013 ITP Near-Term Cost Allocation Forecast

Empire continues to be in the lowest 31st percentile of the utilities shown in *Figure 4.5-12*, as well as representing less than 0.8 percent of the collective ATRR.

3.1.6 Timing of Needed Resources Estimate

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

The SPP Balanced Portfolio of regional transmission projects included no projects in the Empire service territory, therefore, there will be no impact on Empire 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 the previous sections for descriptions of Balanced Portfolio studies and ITP studies.

3.2.1 Utility Participation in RTO Transmission Plan

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

Empire actively participates in the development of SPP transmission expansion plans through a number of related activities. Please refer to *Table 4.5-6* (previously provided on Page 4.5-30), which lists three dozen SPP stakeholder committee/task force involvements. Several of these groups are directly involved with development of the SPP transmission plan.

Empire is a voting member of the MDWG that reviews and updates the transmission planning models used for regional transmission expansion analysis. Empire adds transmission projects into the planning models and provides a substation level load forecast for the seasonal and future years planning models. These models include the generation dispatch Empire expects to be required for meeting its native load requirements. The analysis of these models identifies future transmission projects necessary to maintain reliable service and reduce transmission congestion.

Empire is also a voting member of the TWG which works on issues of coordinated planning and NERC and SPP compliance with individual transmission owners. The TWG is responsible for the planning criteria for evaluating transmission additions, seasonal available transfer capability (ATC) calculations, seasonal flowgate ratings, oversight of coordinated planning efforts, and oversight of transmission contingency evaluations. 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 ESWG to develop the scope documents used to direct the analysis and studies performed for the ITP process.

In addition, SPP hosts multiple ITP workshops each year seeking stakeholder input to the transmission planning process and providing analysis results for stakeholder review. The workshops allow SPP stakeholders to provide input on assumptions for economic analysis and propose transmission projects to reduce congestion and improve reliability. Empire reviews transmission projects in its area and proposes alternatives that may provide better benefit or requests restudy of projects that it believes are not required.

3.2.2 **Annual Review of RTO Expansion Plans**

> *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;*

Empire reviews SPP overall expansion plans each year specifically for transmission projects in its area. Empire proposes better alternatives, where applicable, and/or requests restudy for projects that it believes are not required. In other instances, Empire may suggest solutions to resolve a transmission problem in order to temporarily delay or potentially avoid new transmission construction. Empire also submits alternative upgrade projects and their associated NTCs to be withdrawn if the requirements for the project changes or if the project is delayed beyond the scope of the study process, thereby postponing project construction or submitting.

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;

Empire reviews SPP transmission expansion plans each year specifically for projects in its area. Some of these are zonal projects that may result in additional obligations to serve or for Empire to comply with specific planning and bulk electric reliability criteria.

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

Empire's participation in the SPP planning processes is continuous throughout the year, directly participating on SPP committees, workgroups, and projects reviewing transmission plans and providing recommendations. Empire reviews SPP overall expansion plans each year specifically for transmission projects in its area. Empire proposes better alternatives, where applicable, and/or requests restudy for projects that it believes are not required. In other instances, Empire may suggest solutions to resolve a transmission problem in order to temporarily delay or potentially avoid new transmission construction. Empire representatives also participate in the overall approval of SPP transmission expansion plans in the market and operating policy committee (full membership) and the 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.

Empire does not currently have any affiliate-built transmission at this time.

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 in the appendix to this report.

1. Appendix 4.5B - SPP Balanced Portfolio Report Dated June3 23, 2009.
2. Appendix 4.5C - SPP Priority Projects Phase II Final Report Dated April 27, 2010.
3. Appendix 4.5D - 2012 SPP Transmission Expansion Plan Report Dated January 31, 2012.
4. Appendix 4.5E - 2012 Integrated Transmission Plan Near-Team Assessment Report Dated January 9, 2012.
5. Appendix 4.5F - 2012 Integrated Transmission Plan 10-Year Assessment Report Dated January 31, 2012.
6. Appendix 4.5G - 2012 Integrated Transmission Plan 20-Year Assessment.

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;

There are no transmission upgrades needed at present to physically interconnect a generation source within Empire's footprint. Empire cannot provide a generic list of the transmission upgrades needed to physically interconnect any given generation source within the SPP footprint. Since each interconnection is unique, and each evaluation is site specific. Each Generation Interconnection request is required to submit to the SPP Generation Interconnection process as defined in the applicable SPP transmission tariff. This process examines the specific location proposed for generator interconnection, its unique technical characteristics, and determines the necessary transmission upgrades necessary for that unique interconnection, as required by SPP.

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;

Requests for firm transmission service are processed through the AFS process in the SPP. Since the AFS is an iterative process, it is not possible to identify a list of the specific transmission upgrades needed to generally deliver energy from a resource in the SPP footprint into Empire unless the process for a specific Transmission Service Request has been completed.

The AFS process occurs three times each year when specific Transmission Service Requests and Generation Interconnection requests are modeled collectively across the entire SPP footprint, based on control area to control area transfers. SPP analyzes the transmission system for the service requests including transmission improvements are identified that would enable the service to occur without standard or criteria violations. Costs for the various upgrades deemed necessary to deliver all of the Transmission Service Requests are allocated or socialized to all transmission customers within SPP. Transmission customers may decline the allocated costs and drop out of the study process, after which the analysis is repeated for the reduced set of Transmission Service Requests. This process iteration continues until a final set of Transmission Service Requests is reached for the remaining customers. 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 cost allocations. These remaining upgrade projects are included in the next cycle of SPP transmission expansion plan process.

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;*

Empire cannot provide a list of specific transmission upgrades needed to interconnect a generation resource located outside the SPP footprint without performing a project-specific for SPP Generation Interconnection request for a particular project 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;*

A list of the specific transmission upgrades needed to enhance deliverability of capacity and energy from a particular generation resource located outside the SPP footprint cannot be obtained without actually making a SPP Generation Interconnection request and an associated Transmission Service Request at a particular location.

3.4.5 **Transmission Upgrades Report - Estimate of Total Cost**

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

Empire presently does not have any active NTCs on file with SPP, therefore, the estimated total cost of each transmission upgrade is $0 (zero). In the initial 2012 ITPNT study process, Empire had a total of four active NTCs. Upon internal review of these projects and as a measure of prudency, Empire requested these projects to be re-evaluated so that the new transmission configuration resulting from the May 22, 2011 Joplin tornado along with the loss of load and overall load growth reduction could be incorporated into the study and allow for adjustments. As a result, the SPP Board of Directors approved the withdrawal of each NTC due to the above changes experienced within the Empire footprint. Presently there have been no NTCs issued to Empire since the 2012 ITPNT study; however, Empire continues to participate in the SPP planning process in an effort to continually study the evolution of the regional transmission system.

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.

Empire's estimated fraction of the total cost of transmission upgrades is unknown at this time. Due to the fact that Empire has no active NTCs in which direct charges will be applied, the costs for Empire-specific projects is $0 (zero). However, due to the incompleteness of the SPP Balanced Portfolio process, it is still undetermined as to the proportion of cost to be attributed to Empire from alternative control area regionally allocated projects. 2013 ITPNT zonal cost allocations are displayed in *Figure 4.5-13*.

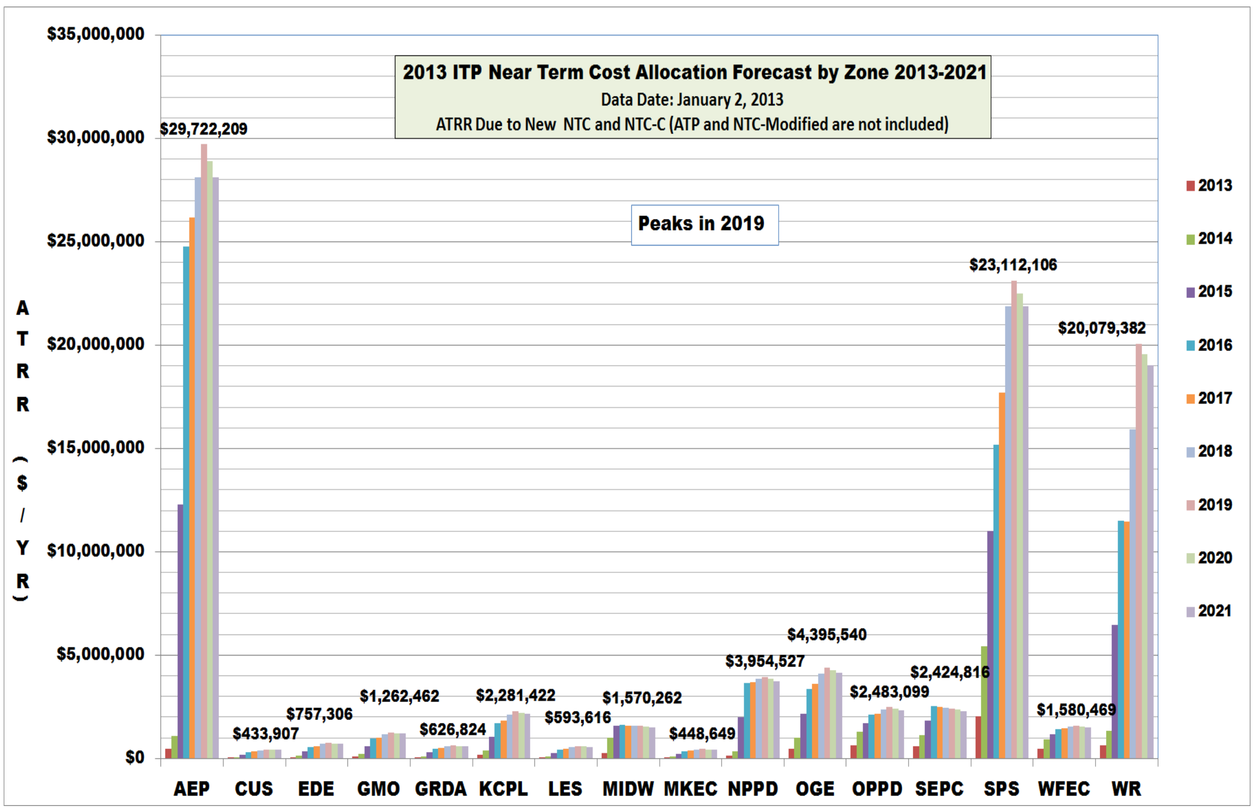

Figure 4.5-13 - 2013 ITP Near-Term Zonal Cost Allocations

Empire's projected cost is $757,306.

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.

Empire incorporates three main advanced technologies in its transmission system: ADSS and/or OPGW, microprocessor relaying, and automatic throw-over switching schemes on the 69-kV transmission system(s) as previously discussed in Section 3.1.2.

4.1.1 Operation Toughen Up

The most recent and extensive transmission and distribution improvements that incorporate advanced technologies are the product of Empire's Operation Toughen Up (OTU) program. OTU is an intensive review of issues related to SAIDI and SAIFI on the Empire distribution system. An anticipated amount of $100 million over 10 years was devoted to reducing SAIDI and SAIFI. The two aspects of this initiative involve both transmission and distribution.

In 2010, Empire started the OTU initiative. The focus of the initiative was to lower the SAIDI and SAIFI for Empire customers and increase reliability of the transmission and distribution systems. Individuals within the various facets of Empire were selected for an implementation team in an effort to gain perspective and representation from operations, transmission construction, system protection, and reliability departments. A steering committee was also formed from differing internal departments so that a broad spectrum of specialties would be available to offer guidance to the OTU team. The steering committee tasked the OTU team with addressing the SAIDI and SAIFI for the customers as well as increasing the reliability for power delivery over a 10-year period and allocated $100 million to be used over the 10-year period to address such needs by developing system improvement/hardening plans for existing facilities and future installations which will result in more reliable service for Empire customers. In its efforts, the OTU team was to recommend projects to the steering committee to be addressed and given support by the various Empire departments to budget, scope, and implement the proposed projects.

The OTU team's review of SAIDI and SAIFI for the distribution and transmission systems and root cause analysis for reported outages relates the indices to causal elements, and proposals for addressing these elements are reflected on an entire system or a more focused effort is applied. As the initial step for evaluation, data was compiled to trend outage causes as compared to the month in which the outage occurred. This data was used as not only a springboard to launch remediation efforts, but also as progress trackers over the course of the initiative. *Figures 4.5-14, 4.5-15, 4.5-16,* and *4.5-17* exhibit the Empire cumulative system SAIDI, Empire cumulative system SAIFI, EEI system outage causes, and Empire-related outage causes.

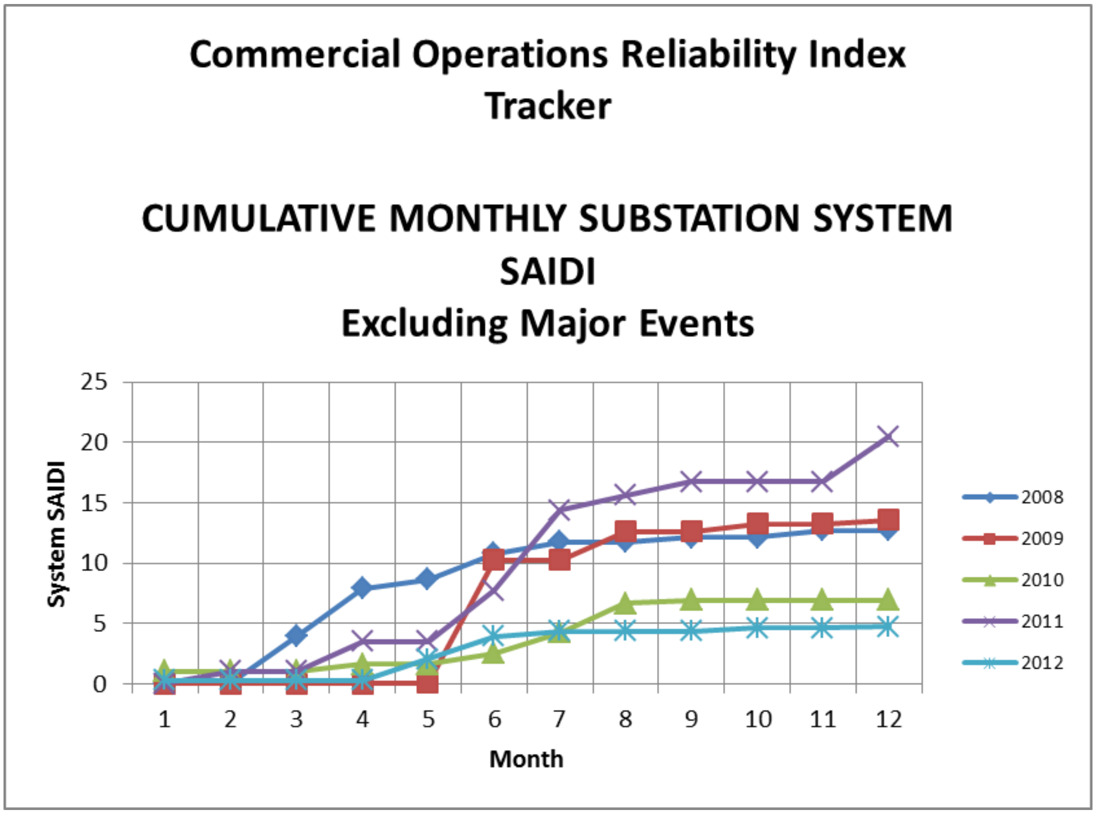

Figure 4.5-14 - Cumulative Monthly Substation System - SAIDI

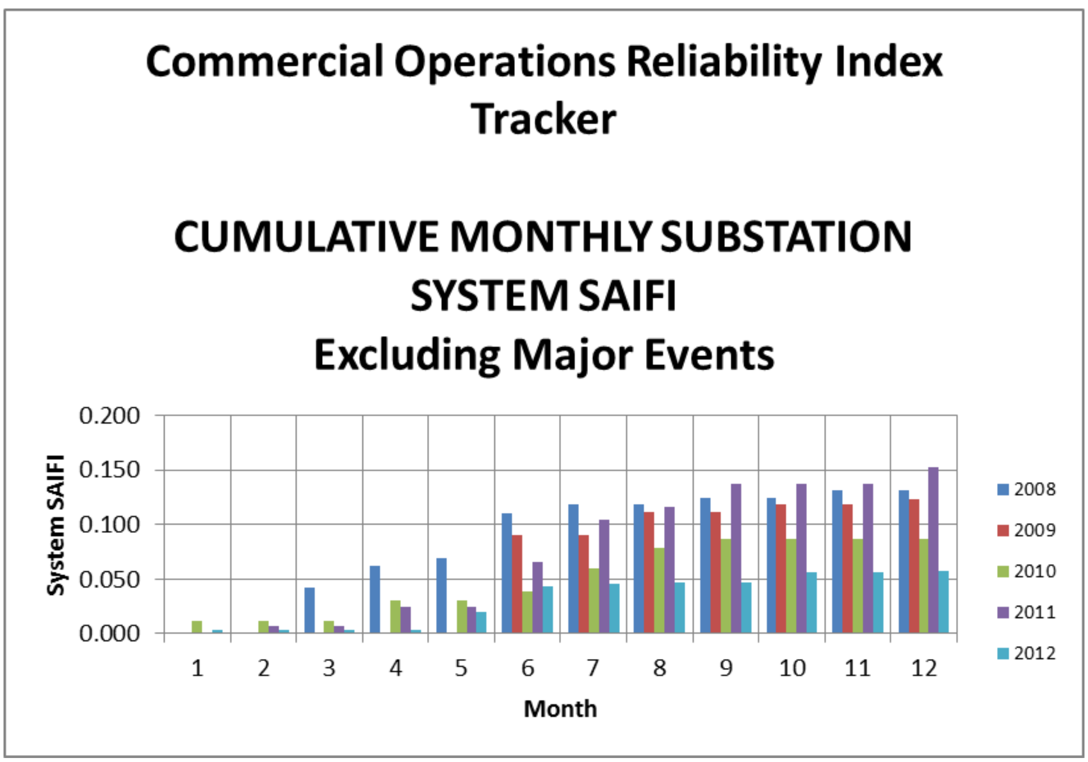

Figure 4.5-15 - Cumulative Monthly Substation System - SAIFI

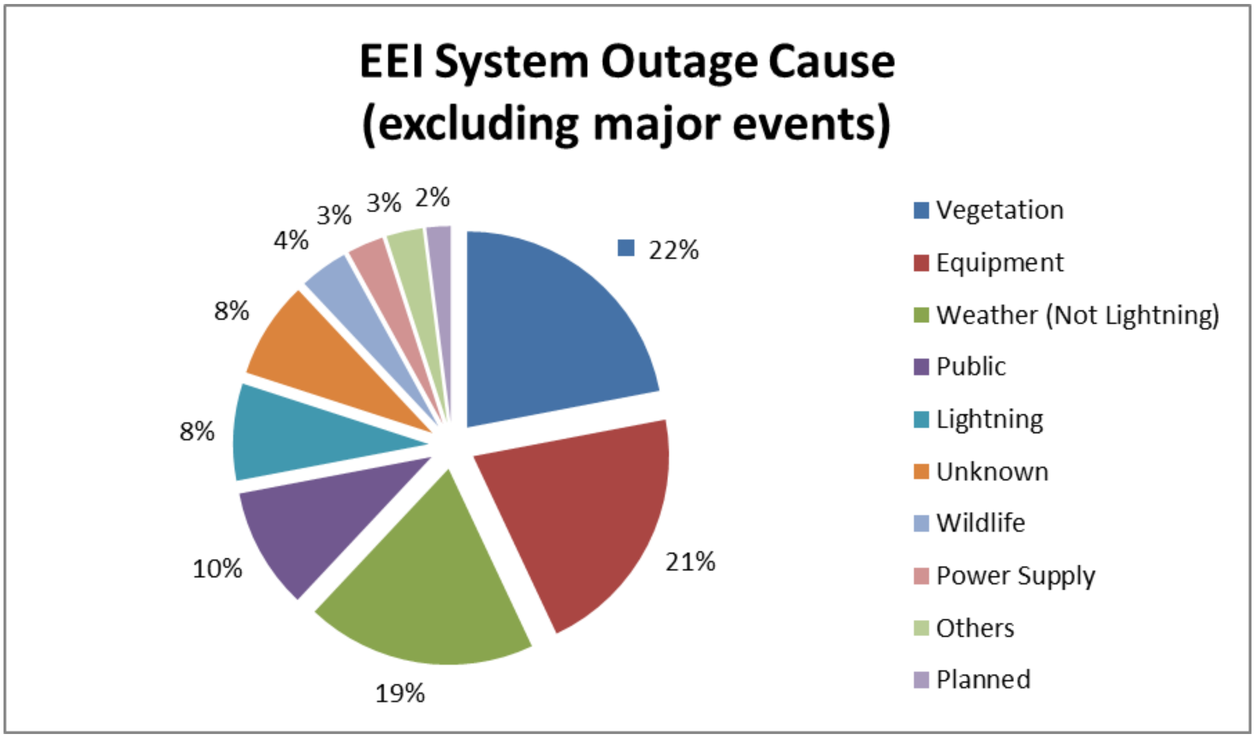

Figure 4.5-16 - EEI System Outage Cause

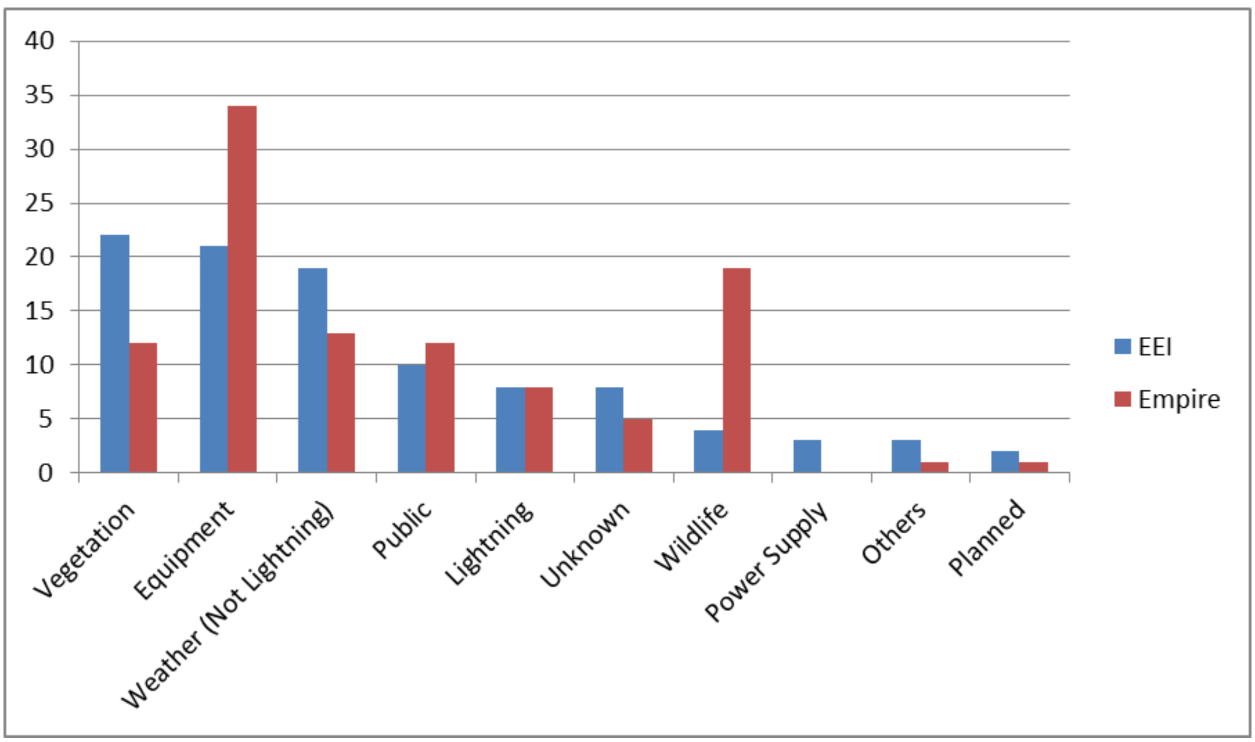

Figure 4.5-17 - Empire-Related Outage Causes

As shown in the above charts, Empire outages as compared to the EEI-reported outages are more frequently caused by equipment failures, public, and wildlife. In reviewing these causes, the reliability and OTU teams developed means to address Empire-specific outage causes and ways to better insulate customers from the most common outage causes experienced on the Empire system by using advanced technologies to better automate restoration efforts and improve response time to outages. An example of such is the auto-throw schemes that were developed for various load taps on the 69-kV system.

The auto-throw schemes were identified as a sound solution to radially tapped load delivery points on the transmission system. The 69-kV system has multiple taps to allow for minimal transmission to be built thereby reducing the impact to customers' rates and right-of-way footprints. The caveat to tapping an existing transmission line versus looping the transmission system is that such taps create a radially fed substation. This radially fed substation is affected by possible faults on either side of the tap (i.e., if a fault occurs on the east side of the tap with breakers at either end of the transmission line, both sides of the tap experience operation). This causes the radially (tapped) substation to experience possible outages as a result of either line section faulting. The determined solution is to apply auto-throw schemes to drastically reduce the exposure for a tapped substation. As the need for a system-wide solution was proposed by the OTU team, Empire engineering developed a standardized auto-throw scheme to be applied to radially fed 69-kV substations. Standardization of the schemes, not only allows Empire to realize lower cost installations for its customers as compared to uniquely engineered solutions, but synergy is achieved between the various groups within the engineering departments. The auto-throw schemes encompass installation of motor-controlled switches, microprocessor relaying, and breaker coordination which when integrated into a packaged system, allows the exposure for the radially fed load to be drastically reduced. As faults occur, either temporary or permanent, the breakers on either end of the transmission line operate as needed to protect their respective line sections. With the addition of the auto-throw schemes, the motor-operated switches with integrated microprocessor relaying automatically senses the fault, tests either line section for where the fault occurred, and opens the faulted line section while restoring connectivity to the radially line. By incorporating advanced technologies, Empire has significantly reduced the exposure for these tapped load locations and has already experienced a reduction in SAIDI and SAIFI.

In addition to the auto-throw schemes, advanced technologies on the 69-kV systems include replacement of electromechanical relaying with microprocessor relaying, installation of additional breakers with microprocessor relaying for improved sectionalization of the transmission system, and utilization/integration of fiber optics with protective relaying communications to further reinforce continuity.

Table 4.5-11 provides a description and schedule of the OTU projects that are planned for the next three years.

Project Type	In Service Date	Description
Transmission Breakers	April of 2013	Install transmission breakers between Joplin 5th street (#284) and Joplin 10th street (#64) Substations, impacting Joplin downtown customers.
Transmission Breakers	2014	Engineer two transmission breakers at Neosho-West Substation (#56) impacting customers in the Neosho and Seneca areas.
Transmission Breakers	2014	Engineer two transmission breakers at Wentworth-West Substation (#205) impacting customers in the Wentworth, Sarcoxie and Pierce City areas.
Transmission Breakers	2014	Engineer two transmission breakers at Diamond-H.T. Substation (#131) impacting Diamond and Granby customers.
Transmission Breakers	2014	At Fairgrove South Substation (#397), this project adds a third 69kV breaker as well as replaces the existing line relay panels. A differential relay panel and communications panel will also be added.
Transmission Breakers	2015	At Fairland West Substation (#363), this project adds 2 69-kV breakers and associated relay panels. The addition of a 2nd motor operator and 69-kV auto throw-over relay scheme will further increase reliability to the area. Line Work: Install 300' of new conductor to tie Shell Substation into existing 69-kV line. Reroute the incoming and outgoing line segments to allow the breakers to be installed. Additional line rerouting may be required to protect the (#261) Fairland shell tap protection. Line rerouting may not be as severe, with the moving of a switch and some bus work inside of the substation to serve Fairland shell (#261).

Project Type	In Service Date	Description
Transmission Breakers	2015	At Republic Hines Street Substation (#451), this project adds another 69-kV dead end structure, 2 69-kV breakers, and associated relay panels. Line Work: Install 300' of new 69-kV line and remove existing transmission switches.
Transmission Breakers	2016	At Joplin-Fir Road Substation (#417), this project adds 2 161-kV breakers, a control enclosure, and associated relay panels. At Carl Junction East Substation (#366), this project adds a motor-operated, auto throw-over switch scheme. At Joplin Oronogo Junction Substation (#110), this project replaces the existing line relay panel on the line to Asbury (breaker #16154).
Transmission Breakers	2016	Substation Work: At Columbus S.E. Substation #94, this project adds 5 69-kV breakers in a ring-bus configuration, a control enclosure, and associated relay panels. At Columbus Tennessee St. Substation (#282), this project adds a motor-operated, auto throw-over switch scheme. Line Work: Existing lines will need to be rerouted to allow for the substation expansion and inclusion of 69-kV breakers. Provisions should be made for a fifth new line segment exiting the substation to serve the current Columbus tap.
Automated Transfer Scheme	May of 2013	Install at Webb City - Cardinal Substation (#436) impacting Webb City customers.
Automated Transfer Scheme	May of 2013	Install at Nixa - North Substation (#114) impacting Nixa area customers.
Automated Transfer Scheme	2014	Engineer transfer scheme at Joplin 2nd Street and Division Substation (#372) impacting Joplin area customers.
Automated Transfer Scheme	2016	Engineer transfer scheme at Brighton - East substation (#323) impacting Brighton area customers.
Automated Transfer Scheme	2014	Engineer transfer scheme at Sarcoxie - Southwest Substation (#362) impacting Sarcoxie area customers.
Re-closer Control Replacment	2014	Three-Phase Recloser Control Replacement: Replace approx. 15 outdated controls on distribution reclosers throughout system. This project will provide sequence coordination of downstream reclosers; it will also provide better data collection and fault finding capabilities to help reduce SAIDI.
Reconductor	2014	Replace 0.27 miles of #6 CU rotten three phase to 336 ACSR along Knox Avenue from Evergreen to Texas Avenue on Hollister East (#387-2) (this has 336 ACSR on both sides).
Reconductor	2014	Replace 0.6 miles of #6/#8 solid CU 3ph conductor with 1/0 ACSR along 12th Street between Euclid and State Line Road in Galena, Kansas.
Reconductor	2014	Replace 0.54 miles of 8 X rotten single-phase conductor to 1ph 1/0 ACSR along FR82 on Greenfield (#614-2) (2 miles north of Greenfield).
Reconductor	2014	Replace 0.54 miles of 6 X rotten single-phase conductor to 1ph 1/0 ACSR alongFR142 on South Greenfield (#614-1).

Project Type	In Service Date	Description
Reconductor	2014	Replace 0.55 miles of 6 X rotten single-phase conductor to 1ph 1/0 ACSR (South of Fairplay on Hwy 123 going west; north of 455th Road) on Fair Play East (#217-2).
Reconductor	2014	Replace 0.17 miles of overhead 3ph deteriorated conductor with 3ph 1/0 ACSR along Johnson Drive in Neosho, Missouri.
Reconductor	2014	Replace 3 miles of 8A overhead single-phase deteriorated conductor with 1ph 1/0 ACSR along Base Line Boulevard (Missouri Highway N) from CR120 to CR90 SE of Jasper, Missouri.
Reconductor	2015	Replace 0.14 miles of #6 CU rotten 3ph conductor to 3ph 1/0 ACSR in downtown alley between Church Street and College Avenue (East of Jefferson Park) in Aurora on Aurora Circuit (#124-2).
Rebuild	2016	At Baxter Springs West Substation (#271), this project replaces identified B.O. porcelain on switches, bus supports, and D.E. insulators. Line Work: ***2014:*** Construct Phase 1 of 69-kV rebuild from Welch-North (#186) to Chetopa-Twin Valley (#388). ***2014:*** Engineer and purchase rights-of-way for Phase 2 of 69-kV rebuild from Welch-North Substation (#186) to Chetopa-Twin Valley Substation (#388). ***2015:*** Construct Phase 2 of 69-kV rebuild from Welch-North Substation (#186) to Chetopa-Twin Valley Substation (#388).

Table 4.5-11 - Three-Year Operation Toughen Up Schedule

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.

Empire's most recent and extensive T&D improvements incorporating advanced technologies involve the OTU program. OTU is an intensive review of issues related to SAIDI and SAIFI across the Empire distribution system. An anticipated amount of $100 million over 10 years was devoted to reducing SAIDI and SAIFI. The two aspects of this initiative involve both transmission and distribution. The relation of OTU to Empire's distribution network is a compilation of sectionalization evaluations, fuse coordination optimization studies, advanced recloser control upgrades, and the implementation of system hardening. All the aforementioned aspects involve the utilization of advanced technology in accomplishing the centralized goal of reducing Empire customers' SAIDI and SAIFI.

As Empire internally evaluates system performance and identifies specific circuits to be addressed, efforts are applied to the improvement of the identified circuit. Topographical data is obtained from the existing infrastructure by way of field personnel and engineering technician evaluations. The circuit is then modeled in a complex software environment (CYMDIST and CYMETCC) which allows the distribution engineer to model the network in close detail. The modeled network then is reviewed for system response as various fault locations are applied. The result is recommended areas of systematic sectionalization by way of recloser (three phase and single phase) installations with advanced relaying, fuses, and system connectivity.

4.2.1 **Welch Feeder Automation System**

An example of the utilization of advanced technologies throughout the distribution network is the Empire Welch Substation Feeder Automation System (FAS). A need was identified on a specific feeder which was experiencing longer duration outages than the Empire system average. The feeder in question is fed by way of an approximately 26-mile long radial transmission line; the subsequent distribution feeder extends an additional 14 miles. Any permanent fault along any portion of the 40 miles of exposure could potentially result in an extended outage situation. This exposure coupled with the remote location highlighted this specific distribution feeder as a candidate for automation. The system developed resulted in a distribution automation solution. The project encompasses seven communication radios, two RTU installations, two repeatable antennae, three recloser installations with microprocessor controls, one SCADA mate switch and associated control, two substation breakers, one real-time automation control, and one human machine interface (HMI), all integrated to compile a self-healing network. A schematic of the system is presented in *Figure 4.5-18*.

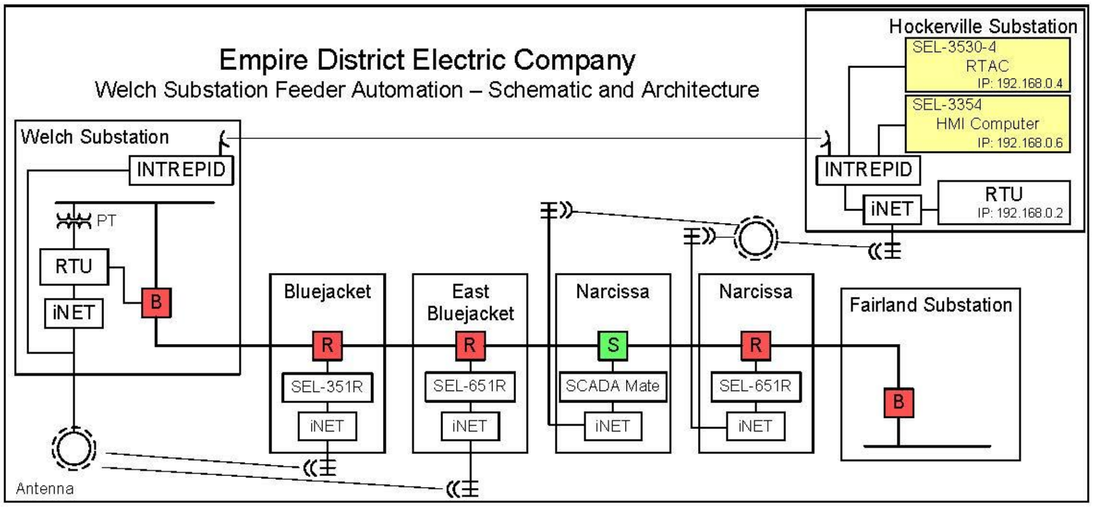

Figure 4.5-18 - Welch Substation Feeder Automation System Schematic

The overarching control of the FAS is referred to as a “scheme”, and entails the monitoring and control of the distribution system equipment (substation breakers, reclosers, and switches) included in the FAS extent of control (i.e., other equipment may exist on the power system but is not of interest to or included in the FAS). The FAS defines a feeder (or circuit) as the connected circuit path extending from a source object (e.g. a power source to the system) through closed circuit disconnecting devices up to open disconnecting devices. Feeders can be complex, involving several devices, branches, and line objects, and they are dynamic, changing in response to device open/close operations made by operations people, automatically by the device overload/protection elements or by the FAS itself.

The FAS provides to the Empire SCADA system, system-wide control of the scheme via an enable/disable control point. The FAS provides a “Reset” command and status information for the scheme to the SCADA system. Additionally, the FAS provides the ability for SCADA users to control the breaker, reclosers, and switch, and to change the settings group active in the reclosers.

The complex nature of the installation along with communications complexity restricts the ability to implement this enhancement system wide. However, because of the unique nature of the radial topology of the feeder in question, this project has served the area customers well and drastically reduced the outage time experienced during adverse events.

Other advanced technologies utilized on the Empire distribution system involve the upgrade and replacement of advanced recloser controls and advanced fusing studies. Empire presently has an additional reliability improvement initiative to upgrade existing recloser controls to microprocessors. In doing so, operability, specifically in rural areas, will be further refined, coordination improved, and enhanced sectionalization will be gained.

4.2.2 Advanced Recloser Controls

Empire realized the merits in implementing microprocessor controls and decided to move forward in standardizing towards a more flexible and advanced control type. The advanced recloser controls have the ability to independently operate on a single phase as compared to former control types having strictly a three-phase operability. In utilizing single pole tripping, single phase to ground faults' effects on a given phase (which account for the majority of fault types) do not affect customers served on an alternate phase(s).

4.2.3 Fusing Studies

Although fusing is not a new technology, Empire has used advanced software modeling techniques to develop superior fusing technique. In past decades, Empire has alternated between fused laterals and non-fused lateral methodology. Attempting to address previous inconsistencies, Empire identified a need to evaluate specific worst performing circuits and standardize fusing criteria. Various conductor and fusing studies were conducted in complementary software platforms (CYMDIST and CYMETCC). These software platforms allow a distribution engineer to model and directly import its modeled protective devices for coordination studies. The distribution engineer is not only able to develop accurate models but additionally review the impacts of specific fuse coordination. Using these tools together, the distribution engineer is able to promote a much more robust system for the customers served off the assessed feeder.

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

At this time, Empire has not yet performed a comprehensive analysis to optimize investments in advanced distribution technologies. These implementations are in their infancy and as a result, Empire will continue to monitor for future comprehensive analysis.

4.3.2 Optimization of Investment - Cost of Advanced Grid Investments

A. Costs of the advanced grid investments;

4.3.2.1 Transmission

Empire utilizes a least-cost, high-value, highest-efficacy approach for optimization of investments for advanced grid technologies. Empire outages triggered by transmission outages were determined as higher impact events due to the large number of customers affected by a single event. By addressing the transmission system and improving sectionalization, high impact outage events were able to be remediated by lower cost installations, thereby optimizing Empire investments in advanced technologies. If radially fed substations are outaged, the resulting number of customers is far higher than if a single circuit sourced from the substation is outaged. As a result, low cost, high impact to outage indices was determined as the optimized solution. This included a review of the causal relationships for transmission outages, radially fed substations, and resultant outage duration. Radially fed substations and outage durations were correlated by which Empire was able to determine auto-throw schemes as the most effective remediation effort. Empire standardized the auto-throw schemes to homogenize installations which has led to optimized installation time and cost. Standardization of the schemes not only allows Empire to realize lower cost installations for its customers as compared to uniquely engineered solutions but synergy is achieved between the various groups within the engineering departments in crafting solutions at different installation sites. In addition to developing a standardized auto-throw scheme, Empire also integrates OPGW and ADSS for protective element communications to improve sectionalization of the transmission system, resulting in lowering the number of high impact outage events.

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

Empire has developed fusing methodology alongside the use of advanced software modeling of the distribution systems. Fusing is considered non-advanced technology due to the longevity of implementation on the electric system. Empire has re-evaluated the methodology used in previous iterations of protective coordination studies and has found improvements could be made in how the distribution system is sectionalized. Evaluation of the fusing methodology entails the use of industry standard fusing and standardization of coordination. Application of the revamped fusing methodology allows for a high efficacy impact on the distribution system sectionalization. By utilizing fusing methodology, Empire has optimized distribution grid investments as opposed to expending efforts and resources in attempting to evaluate newly trended technologies and is able to promote a much more robust system for the customers served off the associated feeders to which the recently formatted methodology is applied.

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.

In addition, Empire reviews scheduled projects for opportunities to upgrade exisiting electromechanical relaying to advanced microprocessor relaying in an effort to gain synergy within the cost of ongoing installations. The benefits of upgrading existing electromechanical relaying includes but is not limited by the following:

1. Fault recording capabilities.
2. Load data profiling.
3. Event analysis.
4. Improved protective device coordination.
5. Reduction in O&M costs.

4.4.1.1.1 **Fault Recording Capabilities**

Electromechanical relaying provides no options for recording capabilities. The lack of recording capability can severely hinder restoration efforts during an outage event. Electromechanical relays simply indicate a fault condition occurred whereas a microprocessor relay has the ability to record pre-fault, fault, and post-fault conditions. These records allow an engineer to review and relate the system conditions to the outage results, thereby reducing the time an outage event exists, lowering SAIDI and SAIFI, and allowing for much more readily realized coordination review.

4.4.1.1.2 **Load Data Profile**

Load data profiles (LDP) are cumulative data which is gathered for a specific feeder in an effort to profile the usage and/or demand occurring within a given timeframe. Electromechanical relaying does not have the ability to digitally gather such data. LDP is tremendously beneficial in reviewing what specific loading a given feeder experiences during various load and weather conditions. Although microprocessor relaying within the substation is one of many available avenues, the effectiveness of various projects (i.e., DSM, reliability efforts, etc.) could be compared to historical loading data gathered for the feeder in question.

4.4.1.1.3 **Event Analysis**

Event analysis allows for an engineer to review pre-fault, fault, and post-fault conditions so as to determine the possible location of a fault, the magnitude of currents experienced during a fault, and the event response by the protective device which cleared the fault. None of these parameters is available on electromechanical-type relaying. Electromechanical relaying is heavily restricted in data gathering and therefore, does not allow for review of such events, but rather strictly a notification that an event occurred.

4.4.1.1.4 **Improved Protective Device Coordination**

Microprocessor relaying does not migrate. The settings issued and uploaded to a microprocessor relay are consistent over time, whereas electromechanical relaying requires constant and consistent maintenance. Over time, the mechanical apparatus experiences various temperatures, humidity conditions, and possible physical aberrations. These conditions lead to migration of the mechanics within the relay. As the relay ages, the migrations can become more pronounced. This leads to possible miscoordination with downstream protective devices as well as unintended operation of the primary protective device. Solid-state microprocessor relays do not experience migration due to the lack of mechanized operation.

With the absence of mechanized operability, more resilient operation over time is realized and protective device coordination is consistent with given parameters.

4.4.1.1.5 **Reduction in Operation and Maintenance Cost(s)**

Electromechanical relaying requires constant maintenance due to the aforementioned issues experienced with mechanical devices. The time and cost associated for maintaining an electromechanical device is relatively small on the forefront of operation, but as length of service increases, the intervals between required maintenance shortens. Empire systematically reviews problematic relay types/models and develops replacement schedules in an effort to reduce O&M costs associated with failures. Empire actively reviews automation applications so as to further reduce the burden non-advanced technologies have on operating the electric system. An example is the automated check back systems on the carrier systems. With the new revision to the NERC PRC-005-02 standard, increased maintenance practices requiring enormous amounts of time and manpower to implement become necessary. Upgrading the existing carrier systems on 16 of the 161-kV line sections will reduce and facilitate the required testing as stipulated by the PRC-005-02 standard. The primary focus of this upgrade is to eliminate the requirement for a manual test of the carrier channel every four months and thereby reduce the manual efforts required in maintaining the non-advanced devices. An additional example is the replacement of electromechanical relaying panels. Empire has developed a standardized line relay panel for upgrades to existing electromechanical relaying panels identified as candidates for replacement. In doing so, the maintenance efforts are greatly reduced and do not necessitate the upgrading of the alternate end relaying panel in addition to laying the foundation for future upgrades to the protective relaying systems. This is a tremendous advantage in realizing upgrades to the protective relaying systems while not requiring an expanded project scope due to issues exhibited at a particular substation while accomplishing the reduction in O&M efforts required for non-advanced relaying technologies.

This standardized relay panel incorporates all microprocessor relaying which eliminates the majority of testing requirements and physical maintenance efforts on the operability of the relays.

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;

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 Distribution

Refer to comments in Section 4.3.1.1.

4.4.6 Optimization of Investment - Other Non-Utility Identified Factors

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

4.4.6.1 Distribution

Text 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 Transmission

Empire is not proposing installation of any new non-advanced transmission grid technologies or programs in this triennial IRP compliance filing. Empire will conduct and document such an analysis which demonstrates such an investment to be more beneficial to consumers than an advanced grid technology if Empire is to include such non-advanced technologies in future IRP filings.

4.5.1.2 Distribution

Empire is not proposing installation of any new non-advanced distribution grid technologies or programs in this triennial IRP compliance filing. Empire will conduct and document such an analysis which demonstrates such an investment to be more beneficial to consumers than an advanced grid technology if Empire is to include such non-advanced technologies in future IRP filings.

4.5.2 Non-Advanced Transmission and Distribution Analysis Documentation

2. Describe and document the analysis.

4.5.2.1 Transmission

Empire is not proposing installation of any new non-advanced transmission grid technologies or programs in this triennial IRP compliance filing. Empire will conduct and document such an analysis which demonstrates such an investment to be more beneficial to consumers than an advanced grid technology if Empire is to include such non-advanced technologies in future IRP filings.

4.5.2.2 Distribution

Empire is not proposing installation of any new non-advanced distribution grid technologies or programs in this triennial IRP compliance filing. Empire will conduct and document such an analysis which demonstrates such an investment to be more beneficial to consumers than an advanced grid technology if Empire is to include such non-advanced technologies in future IRP filings.

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 Transmission

Empire has not been able to develop a cost/benefit (C/B) analysis for the incorporation of advanced transmission technologies. Empire understands that in future IRP filings, they will develop, describe, and document the C/B analysis for such an application and resultant filing(s).

4.6.2 Distribution

Empire has not been able to develop a C/B analysis for the incorporation of advanced distribution technologies. Empire understands that in future IRP filings, they will develop, describe, and document the C/B analysis for such an application and resultant filing(s).

4.6.3 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;

4.6.3.1 Transmission

Usage of advanced technologies on the transmission system includes, but is not limited to, microprocessor relaying and fiber optic relaying communications and has been described in detail within the above sections of this filing. Both have initially served Empire well by incorporating these elements in recent projects. Empire has been able to attain a more robust transmission system due to the expanded protective advantages realized by the inherent benefits to microprocessor relaying and fiber optic communications. Empire not only makes every effort to incorporate both technologies in presently budgeted projects but also actively reviews present relay configurations to determine where merited upgrades would benefit the customers served by the associated transmission line sections.

4.6.3.2 Distribution

Usage of advanced technologies on the distribution system includes, but is not limited to, microprocessor relaying for not only substation breakers but also reclosing applications. Both have initially served Empire well by incorporating these elements in recent projects. Empire has been able to attain a more robust distribution system due to the expanded protective advantages realized by the inherent benefits to microprocessor relaying in addition to improved sectionalization. Empire not only makes every effort to incorporate these technologies in presently budgeted projects but also actively reviews present relay configurations to determine where merited upgrades would benefit the customers served by the associated distribution line sections.

Secondly, the Welch FAS has served as a pilot project in which subsequent installations may be able to be based. It is too early to determine whether this application can be used in alternate locations due to the complexity of not only the installation but also due to dynamic loading characteristics of various alternate feeders. Empire will continue to vet this system as time of in-service increases and will review alternate locations for inclusion. The complex relaying and communications required for such a project has shown to be restrictive in implementation.

4.6.4 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 transmission or distribution advanced grid technologies did not influence the selection of resource acquisition strategy. The aforementioned implementations are preparative in nature to be used as a possible springboard for future deployment and are foundational in possible future development.

Empire anticipates that the subsequent cost benefit analyses will determine that several of the advanced grid technologies will be determined to be cost effective, or at a minimum Empire will understand under what extent of implementation they become cost effective.

At that point, Empire believes the impact of advanced grid technologies on resource acquisition could be evaluated and possibly influence subsequent future filing(s).

4.6.5 Transmission Advanced Grid Technologies Impact Description

3. A description of the impact of the implementation of transmission advanced grid technologies on the selection of a resource acquisition strategy.

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.

Empire attempts to gain synergy with SPP members and non-members in the annual RTO-hosted model building summits, planning summits, and various collaborative joint study meetings. Empire actively participates on multiple working groups and task forces. Empire participates in the development of and annually reviews the RTO reports. Empire annually confirms tie line ratings with interconnected utilities in an effort to maintain communication and congruency during the modeling building process.

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.

No economically viable Empire transmission projects are merited at this time for review by the RTO. Empire previously submitted two high value projects for consideration as a mitigation to multiple overloads and voltage issues around the Joplin and Monett areas. However, after internal re-evaluation during post-tornado reconfiguration using updated of rating methodology, Empire's load has not materialized as initially projected, these projects became unnecessary. Therefore, Empire offered them as restudy candidates to the RTO and submitted NTC withdrawals. Empire has and will continually attempt to identify transmission projects that will have positive impact to their customers.