Kentucky Power Company
KPSC Case No. 2020-00174
Commission Staff's Eighth Set of Data Requests
Dated February 12, 2021

DATA REQUEST

KPSC 8_12 Refer to Vaughan Rebuttal Testimony, page 28. For the most recent three years available, provide Kentucky Power's highest 876 hours of load at each distribution substation for each year. Provide your answer in Excel spreadsheet format with formulas intact and unprotected, and all rows and columns fully accessible.

RESPONSE

Please see KPCO_R_KPSC_8_12_Attachment1 through KPCO_R_KPSC_8_12_Attachment3 for the information responsive to this request that is available to the Company. Interval data is not available for all of Kentucky Power's distribution substations. Interval data for the highest 876 hours for each substation is provided where available. The single highest annual load for each of the three years is provided for each substation where interval data is not available.

Witness: Everett G. Phillips

Kentucky Power Company
KPSC Case No. 2020-00174
Commission Staff's Eighth Set of Data Requests
Dated February 12, 2021

DATA REQUEST

KPSC 8_13 Refer to Vaughan Rebuttal Testimony, page 28. Define "highest distribution loading (peak loads [sic]) events … (and) … the Company designs its distribution system to service the highest peak load."
a. Explain whether peak loads vary by circuit or substation, or both, and provide documents that substantiate your response.
b. Explain Kentucky Power's approach to sizing substations, including, but not limited to, the load forecasts that are utilized for sizing substations and whether a distribution system peak or a more local forecast is used to size substations.

RESPONSE

Peak loading on company facilities is typically driven by increasing temperatures in the summer and decreasing temperatures in the winter. As the temperatures push toward the extreme in either season our customers demand for energy also increases to a point of highest demand. We have to understand what these load demands are for each season and design our system to ensure that facilities are in place with the appropriate capacity to serve our customer demand without interruption of service.

a. Peak loads do vary by station and circuit as they are a function of individual demand by the customer base. Thus, each circuit and substation transformer will have its own unique peak load.

b. We maintain a working distribution system load forecast that compares facility ratings for every KPCo distribution substation transformer and distribution circuit against the latest seasonal peak load, both summer and winter, to determine what a 10 year forward looking view of system loading will be for each transformer and circuit. This forecast is the basis for determining future system capacity additions required to serve customer demand without interruption of service. Substations are sized to allow for future load growth beyond the 10 year forecast window.

Witness: Everett G. Phillips

DATA REQUEST

KPSC 8_14 Refer to Vaughan Rebuttal Testimony in general. Provide Kentucky Power’s distribution system planning guidelines and manuals used for planning, sizing, and replacing distribution system equipment.

RESPONSE

Please see KPCO_R_KPSC_8_14_Attachment1 for the requested information.

Witness: Everett G. Phillips

American Electric Power
Distribution System Planning Criteria

October 2016 Revision

Distribution System Planning Criteria Team (May 2010)

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Section 1

Distribution System Planning Philosophy

The purpose of the planning criteria is to help distribution planners to determine the most consistent orderly expansion and reinforcement of the distribution system. Distribution planners should strive to use good engineering judgment in evaluating and selecting alternative solutions that provide reliable and economic improvements in the service to customers. Final system improvement plans are then developed by selecting the alternatives that provide the best balance between improving customer satisfaction, economic expansion of the system, and available resources.

Distribution system planning is the study, analysis, and project development through which an electric utility plans to economically and reliably meet its future power delivery obligations. The purpose of distribution system planning is to provide a careful analysis of an electric utility's distribution system in order to evaluate alternative methods of meeting the electric power delivery needs of present and future distribution system customers. The planning process results in the alignment of the expansion of the distribution system with goals for safety, reliability and customer service.

Safety must be considered in all aspects of planning the distribution system. AEP's Managing Environment, Safety & Health (MESH) philosophy, ("*No aspect of operations is more important than the health and safety of people. Our customers' needs are met in harmony with environmental protection.*"), must be a central theme in developing distribution plans. Compliance with AEP Safety Procedures as well as recognized national, state and local standards is a basic expectation of this criteria.

The distribution planner should consider that the facilities will have to be operated and maintained in all types of conditions (i.e. weather, terrain, accessibility) over the lifetime of the assets. **Distribution plans need to be flexible to allow designs that maximize the opportunity for safe operation & maintenance of facilities and protection of the environment**. The process of determining the scope of a project must include asking the question; "How can the project scope enhance safety and preserve the environment?" Plan development should include the following steps / considerations:

- Design plans that allow workers to operate equipment from a distance or remotely.
- Design plans that allow workers to de-energize equipment for maintenance.
- Design plans that reduce load losses and improve efficiency, which lead to lower generation emissions.
- Review plans with local operating personnel for any safety or environmental concerns.

It is critical that early in the planning process the distribution planner engages other departments such as transmission asset management, real estate asset management, right of way, regulatory, as well as distribution and transmission operations. In addition, input from the local region engineering and customer service team is critical in understanding the challenges facing local leadership in the areas under review. The process of locating new substations and transmission lines is a complex task. This requires a balance of cost, constructability and effectiveness of resolving the anticipated capacity and/or reliability problems.

Modern distribution planning methods strive to improve the use of company resources and provide better projections of future expenses. Planning uses a long range view of the distribution system needs to make short range decisions with a high degree of confidence that they will be appropriate for the future. The AEP Distribution System Planning Criteria is consistent with industry planning practices nationwide. An effective distribution system planning process will work to select the most promising of many alternatives evaluated for expansion of the distribution infrastructure. Key components of a long range plan include; a) safety of the public, utility employees, and company facilities, b) long range and short range cost considerations, c) meeting the capacity needs of the customer base, and d) providing a reliable distribution system at a reasonable cost.

This document is intended to be used to:

1. Provide both new and experienced distribution planners with a summary of the expectations in developing new project plans.

2. Provide other stakeholders, both internal and external, with an understanding of the elements considered in developing a project plan.

This document provides a basis for measuring the value of the plan elements that can be compared to other system improvements. Project plans that are developed using these criteria are not automatically constructed, however, this document does allow for an understanding of the relative value of distribution system improvements. (This results in selecting projects with the highest short term and long term corporate values.)

Overview of Distribution System Planning

AEP Distribution System Planning consists of forecasting strategic and tactical improvement needs of the distribution system based on both historical and projected load growth. Improvements are evaluated to adequately serve forecasted loads that are ultimately projected to exceed system capacity limits. The core planning focus is on normal loading conditions. Planning to address abnormal system conditions and provide outage recovery falls under Reliability Planning and will be discussed later in this document (See Section 3).

AEP Distribution System Planning Process

Distribution system planning at AEP can be divided into seven distinct tasks:

- Develop a representative model of the existing distribution system

- Work closely with local operational personnel and utilize monitoring systems to observe, document, and evaluate the actual performance of the distribution system during normal system configuration.
- Develop a reasonable, supportable forecast of future loads on the distribution system
- Analyze the existing distribution system's ability to adequately serve the short and long range future loads
- Identify the appropriate solutions to address any deficiencies in the existing distribution system for both the short and long term. Solutions may also include customer-side load management.
- Determine the required in-service period for needed improvements to the distribution system.
- Communicate the financial requirements, the justification for implementing the proposed improvement plans to management, and the risk of not doing the project.

The planning tasks described above require a complete analysis of the existing distribution system. The distribution planner must review the present system and its components and analyze the capability of the components to supply the requirements of the future distribution system. This review will provide insight into the development of a practical transition from the existing system to the system proposed in the long range plan. Factors the distribution planner should consider in developing the long range plan include, but are not limited to:

- Changes in customers' electrical load and usage patterns.
- Selection of appropriate primary distribution voltages.
- Selection of appropriate distribution circuit capacities.
- Selection of appropriate substation capacity requirements.
- Selection of new substation locations.
- Integration of the distribution plan with transmission requirements.
- Location of potential roads and highways.
- Identification of undeveloped land for new loads.

As these factors are evaluated, the distribution planner must include consideration for inherent reliability improvement as a direct result of the selection process. Site selection, line routing and even the preferred distribution voltage can have an effect on the inherent reliability of the distribution system. While capacity and voltage elements are generally the initial focus of the need for improvements, considering a solution that provides a meaningful improvement in the area reliability is desired. In many cases, systemic reliability improvement may be achieved with little to no additional cost if reliability is one of the factors considered in the selection process above. Reliability improvements should be included if the incremental cost is reasonable. Additional information can be found under Reliability Planning in this document (See Section 3).

Once the long range plan is developed, the short range plan can be determined. The short range plan provides the basis for determining the immediate budget requirements for the distribution system compatible with the long range plan. Identifying solutions is based on enhancing the value and reliability of the distribution system by following the improvement steps below. Solutions are then turned into projects subject to prioritization and selection based on the amount of load at risk, the reliability needs of the system, community and regulatory considerations, and available resources.

Selection of Improvement Steps

The distribution planner will consider the following solutions to determine the most economical and reasonable solution that is appropriate for a given condition that does not meet the planning criteria. These steps typically represent least to highest cost solutions. When evaluating a solution, the impact to reliability and outage recovery should be considered (See Section 3).

1. Install capacitor banks to improve voltage or improve power factor, thus relieving capacity constraints.
2. Transfer load to another source with available capacity or better voltage support.
3. Install voltage regulators to improve voltage where capacitors are not the appropriate solution.
4. Upgrade (reconductor, re-space, convert to higher voltage, etc.) existing distribution circuits to relieve capacity constraints and improve voltage support.
5. Construct new distribution circuits to relieve capacity constraints and improve voltage support.
6. Install additional capacity in existing substation facilities with associated improvements to relieve capacity constraints.
7. Construct new substation facilities with associated distribution circuit improvements.
8. Investigate the feasibility of using utility or customer owned distributed generation for peak shaving to provide needed capacity. Potential choices include generators or advanced battery storage systems. Section 4 of this document discusses this in more detail.
9. Investigate establishing a new point of delivery from an unaffiliated electric provider (i.e. distribution interconnection from other utilities) to relieve capacity constraints and improve voltage support.

Long Range Plan Development

The value in the development of the long range plan comes from identifying lowest cost solutions to locating major assets such as substations and transmission lines. It allows for the early determination of the viability of constructing the needed facilities in the required time frame. It also allows the acquisition of land and other land rights for transmission line and station facilities at the lowest possible cost. Therefore, long range plan development should focus on meeting the needs of the distribution system within the planning criteria while considering the following elements:

- Changes in the customers' electrical load using demographic information on land use, available land for development, and natural barriers or enablers that will help predict growth patterns
- Selection of appropriate distribution circuit capacity and design voltage
- Identification of substation sites on undeveloped land
- Evaluation of the transmission line construction requirements that will drive the location of substations
- Constructability of new lines and substations, evaluating all relevant factors
- Choosing a new substation site near/under an existing transmission line can minimize transmission line extension costs. However, if long distribution lines are needed to reach the load center, the added exposure may negatively affect the inherent reliability of the system.

Identifying the future financial needs of the distribution system will assist the development of a long range budget strategy.

Short Range Plan Development

Short range planning involves the detailed evaluation of a given distribution area at the primary circuit level. Typically, short range planning involves analysis, design and lead time for equipment and construction. Therefore, the view for short range planning is a few years as compared to the ten year view typical of long range distribution system planning. The short range plan must be consistent with and support the execution of the long range plan for the area. Therefore short range plan development should focus on meeting the needs of the distribution system within the planning criteria while considering the following elements:

- Relief of existing or immediate projected overloads,
- Proper voltage and power factor improvements,
- Immediate improvement of service quality and reliability,
- Short term system requirements and short term budget estimates.

Section 2

Distribution Capacity Limits – Normal Conditions

In this section the concept of capacity refers to thermal capacity to serve load, capacity to maintain adequate voltage, and sufficient short circuit capacity to allow for adequate overcurrent protection. This section addresses the objective criteria to be used as the benchmark for comparison to actual or projected system conditions. Equipment capabilities are defined for normal and abnormal system conditions. These capabilities form the basis for decision making concerning replacement or addition strategies.

This criteria is intended for distribution system planning purposes only and not as an operating guide. Additionally, these criteria are not intended to replace good engineering judgment or good utility practice.

In this Section, information relating to limiting factors is presented for:

- Substation equipment
- Distribution circuit conductors and equipment
- Voltage performance
- Power factor performance
- Load and voltage imbalance

Substation Equipment

This section addresses the AEP planning criteria for loading of substation equipment during normal system conditions.

When the load on a substation element is projected to exceed its normal calculated capability, a project should be planned such that it will relieve loading or increase capacity at the substation prior to the projected overload. Projects need to be submitted for prioritization and budgeting early enough to allow design and construction to be completed by the needed service date.

Loading limits are provided for the following substation equipment:

- Substation Power Transformers
- Voltage Regulators
- Breakers, Reclosers and other protective devices
- Buses
- Switches
- Reactors
- Ancillary Equipment

The distribution planner may determine that exceptions to these criteria will exist due to prior design philosophies, specific customer requirements, and other circumstances in existing substations. Specific equipment may also have documented poor performance requiring that equipment to be rated less than the ratings specified by the equipment nameplate or by the following criteria.

Substation Power Transformers

The distribution planner will consider normal conditions for substation transformers. The planner will apply the current AEP Station Design Engineering Standard SS-780001 to assist in interpreting transformer test reports and prepare data for transformer capability computer programs such as EPRI PTLoad. For cases where factory test reports do not contain all of the information required to run the computer programs, the standard provides methods for deriving missing data. In the event a computer program is not available, the user can also apply the formulas within SS-780001 to perform hand calculations for determining transformer capabilities under steady state ambient and loading conditions. Transformer capabilities determined through the use of this standard should be applied with appropriate thermal limits described in the current AEP Station Design Engineering Standard SS-780002 "Power Transformer Loading Limitations" and should be supported by test report data, original purchaser's specifications, and other manufacturer documentation. In the event this information is not available, it may be possible to use data from similar transformers. For such cases, a repository of transformer characteristics will be helpful. Careful consideration should be given regarding the limitations of the transformer load tap changer (LTC) and the transformer bushings, as these elements may limit the ability to load the transformer to its calculated capability.

AEP Station Design Engineering Standard SS-780001 refers to the following national standards and guidelines:

- IEEE Standard C57.91-1995,"IEEE Guide for Loading Mineral-Oil-Immersed Transformers."
- IEEE Standard C57.12.00-1993, "IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers"
- IEEE Standard C57.100, "IEEE Standard Test Procedure for Thermal Evaluation of Oil-Immersed Distribution Transformers"
- IEEE Standard C57.131-1995, "IEEE Standard Requirements for Load Tap Chargers"
- AEP Station Standard SS-780002, "Power Transformer Loading Limitations"

Substation Voltage Regulators

The distribution planner should consider normal conditions for substation voltage regulators in accordance with SS-650000 "Voltage Regulators Application Guide". The planner also should assume that all ancillary equipment required by the regulator (e.g.: fans, pumps, bypass switches, etc.) is in working order unless specifically noted. The distribution planner should also remain aware that a regulator may have bushings or other items with limiting ratings less than specified by the regulator's capability. Also, the planner should note that specific regulators may be required to be rated less than their nameplate due to previously documented poor equipment performance.

It should be noted that step type voltage regulators commonly used by AEP have a selectable rating based on the level of regulation required of the device. Typical voltage regulators have the capability of regulating the voltage +/- 10% of the incoming voltage. The range of regulation can be restricted if lesser regulation is required. This limits the heat generated in the device and allows it to operate at a higher capacity. Before using this “load bonus” feature, the distribution planner should determine that the regulation requirements will remain at a reduced level for a reasonable period of time and all operating procedures are duly noted.

Substation Breakers, Reclosers and other protective devices

For substation breakers, reclosers and other protective devices, the distribution planner considers the continuous current rating and the interrupting rating in accordance with applicable station design and engineering standards. The planner should also assume that all ancillary equipment required by protective devices is in working order unless specifically noted. Planners should also remain aware that a protective device may have bushings or other items with capabilities less than the continuous rating of the equipment. The planner should also note that specific protective devices may be required to be rated less than specified by the equipment nameplate due to documented past equipment performance. Indoor power circuit breakers (or switchgear breakers) should be considered with all applicable capability limitations as with substation breakers, reclosers and other protective devices.

> **Normal Loading Conditions:** Substation breakers, reclosers and other protective devices should be planned for replacement prior to the forecasted load exceeding the device’s nameplate rating.
> **Interrupting Rating:** Substation breakers, reclosers and other protective devices should be planned for replacement prior to the forecasted maximum available fault current exceeding the breaker or recloser’s interrupting capability. Reactors may be used to reduce the fault current, if appropriate.

Substation Buses

The distribution planner should consider normal conditions for substation buses. Substation buses are designed to act as a heat sink for equipment connected to it, thus drawing heat away from those devices. The bus should be designed to operate in accordance with the current Station Design Engineering Standard SS-060000.

Switches

Substation switches may be loaded to their continuous current capability, which is usually their nameplate rating. The distribution planner should consider normal conditions for substation switches in accordance with SEP-E–133 and will consult with the station design group if there are special or specific application questions.

Reactors

Substation reactors should be loaded to their continuous current capability, which is usually their nameplate rating. The distribution planner should consult with the station design group if there are special or specific application questions.

Ancillary Equipment

The distribution planner must be careful to recognize that there is ancillary equipment within the distribution station that can limit the capability of major equipment. It may seem that this equipment is minor relative to the larger assets noted above, but their failure can cause damage to major equipment resulting in long outage recovery times. Some of the equipment to be evaluated includes:

- Current Transformers (CTs) in the current path
- Bus connectors
- Station service transformers
- Battery capability

Distribution Circuit Conductors and Equipment

This section addresses the AEP Distribution System Planning Criteria for loading of overhead and underground distribution conductors and equipment.

When the load on a circuit element is projected to exceed its normal capability, a project should be planned such that it will relieve loading or increase capacity on the circuit prior to the projected overload. Projects need to be submitted for prioritization and budgeting early enough to allow design and construction to be completed by the needed service date.

Overhead Conductors

Overhead conductors may be loaded to their calculated ampacity based on the maximum design operating temperature and expected ambient conditions in the area. The ampacities are also based on maintaining clearances required by the NESC. In general, ampacities in CYMDIST will be used. However, it is recognized that there are minor differences in conductors, conditions and operating temperatures. Refer to the AEP Distribution Engineering Manual (East Operating Companies) or the CSW Distribution Planning Guide (West Operating Companies) for additional ampacity ratings.

The standard maximum conductor operating temperatures of primary overhead conductors for new construction are 65 degrees Celsius for #2 and #1/0, and 100 degrees Celsius for #4/0 and larger conductors. However, existing distribution lines may have been constructed to different conductor operating temperatures.

Underground Conductors

Underground conductors may be loaded to their calculated ampacity based on the maximum design operating temperature and expected ambient conditions in the area. Refer to the AEP Underground Engineering Manual (East Operating Companies) or the CSW Distribution Planning Guide (West Operating Companies) for ampacities. Use CYMCAP to calculate the ampacity of groups of circuits in close proximity to each other where mutual heating can affect the ampacity. AEP Network Engineering can assist with calculating ampacities for additional specific applications.

Distribution step-down/step-up transformers

The thermal capability is determined from the latest revision of ANSI/IEEE C57.91, "Guide for Loading Mineral-Oil-Immersed Overhead and Pad-Mounted Distribution Transformers Rated 500 kVA and less with 55 Degree C or 65 Degree C Winding Rise". For transformers rated above 500 kVA, the thermal capability is determined from the latest revision of ANSI/IEEE C57.92, "Guide for Loading Mineral-Oil-Immersed Power Transformers up to and Including 100 MVA with 55 Degree C or 65 Degree C Winding Rise".

Distribution line voltage regulators

Distribution line voltage regulators are used to control distribution voltages where installing capacitors is not appropriate. As a general rule, the distribution planner should not install more than three voltage regulators in series (the substation unit plus two distribution line units) to provide normal voltage support. This is due to the difficulty of coordinating the time delay settings of the various regulators in series.

Loading of distribution line voltage regulators will follow the guidelines in AEP Report 761. Voltage regulators have a selectable rating based on the level of regulation required by the device. Typical voltage regulators have the capability of regulating the voltage +/- 10% of the incoming voltage. The range of regulation can be restricted if lesser regulation is required. This limits the heat generated in the device and allows it to operate at a higher capacity. Before using this "load bonus" feature, the distribution planner should determine that the regulation requirements will remain at a reduced level for a reasonable period of time and all operating procedures are duly noted.

Protective Devices

The distribution planner should not load any protective device, such as reclosers, sectionalizers, or fuses greater than the continuous rating or minimum trip value (whichever is less) under any conditions. The planner should also consider the continuous ratings of riser wires, disconnect switches, and connectors. In addition, distribution protective devices should be planned for replacement prior to the forecasted maximum available fault current exceeding the protective device's interrupting capability. Distribution protective devices are discussed in more detail in the AEP Distribution Overcurrent Protection Guide D-OCP001.

Steady State Voltage

Due to the dynamic nature of loads served by an electric utility, it is normal to expect voltage fluctuations. These fluctuations result in deviations from normal steady state voltages measured in RMS voltage at various metering points. AEP follows the National Voltage Standard ANSI C84.1 or local state rules governing electric service, whichever is applicable. The national standard as well as local state rules apply to measurements taken at the point of delivery to the customer. Using sound engineering judgment, AEP may operate the distribution system at slightly different values as long as the standards are met at the delivery points. Steady state voltage fluctuations include the following:

- Steady State Voltage Deviations
- Steady State Voltage Unbalance
- Steady State Voltage Harmonics

Steady State Voltage Deviations

Steady state voltage deviations are measured in RMS and have durations ranging from minutes to hours. Steady state conditions do not cover events measured in sub-cycles, cycles or seconds. Steady state primary voltage variations on a 120-volt base will range from 126 V to 117 V (105% to 97.5%) for normal conditions, and range from 127 V to 114 V (106% to 95%) for abnormal conditions. Steady state voltage magnitudes at any point along the circuit should be held within the range of maximum and minimum values as filed with the appropriate state utility regulatory commissions, or as set by the latest revision of ANSI/IEEE C84.1 as appropriate.

Steady State Voltage Unbalance

Per ANSI C84.1, utility steady state voltage unbalance is calculated by using measured phase-to-phase voltages, under no load conditions at the utility transformer. The voltage percent unbalance is the maximum difference between any phase-to-phase voltage and the average of the magnitudes of all three phase-to-phase voltages, expressed as a percentage of the average of the magnitudes of all three phase-to-phase voltages as shown below.

$$\% \text{ Voltage Unbalance} = \frac{[\text{ (Max. or Min. phase-to-phase voltage)-(average phase-to-phase voltage)}]}{\text{average phase-to-phase voltage}} * 100\%$$

The maximum voltage unbalance should not exceed 2.5% at the primary or secondary level. AEP adheres to this steady state voltage unbalance or others if local state rules apply.

Steady State Voltage Harmonics

Harmonic voltage distortion is generated by loads that rectify or convert voltage from AC to DC. These loads include adjustable speed drives, arc furnaces, induction furnaces or any other large loads that rectify voltage. AEP follows IEEE 519 guidelines or local state rules, if applicable, to limit harmonic voltage distortion.

Power Quality Voltage

This section addresses non-steady state conditions or events measured in cycles or seconds. These power quality events are usually referred to as transitory or transient. The distribution planner should consider transient effects of system voltage due to large dynamic loads such as large motor starts, arcing loads, or other lock rotor loads when planning the distribution system. The following power quality voltage events include:

- Voltage sags and swells
- Voltage flicker

Voltage Sags and Swells

Voltage changes that result from abrupt load application, or cyclic load changes which affect customers' facilities, should not exceed the values indicated in AEP Distribution Engineering Standards. Voltage changes resulting from the various types of transient load changes described do not need to meet the specified limits under certain conditions. This is allowable if such changes do not affect the operation of other customers' facilities and if satisfactory operation of the producing customer's equipment is attained. If such momentary changes affect other customers' facilities, remedies or preventive measures shall be taken to satisfy the operation of those customers. If it is determined that a customer is the cause of the voltage changes, the customer is typically responsible for all costs to resolve the problem.

Voltage Flicker

Voltage flicker occurs when cyclic load changes repeatedly and affects the perception of voltage quality. Industry has developed visibility and irritability curves to guide in the evaluation of voltage flicker. AEP follows the range of observable and objectionable voltage flicker versus time as shown in Figure 3-8 of IEEE Std. 141-1993. If voltage flicker is unacceptable, measures shall be taken to reduce or eliminate the flicker. If it is determined that a customer is the cause of the voltage changes, the customer is typically responsible for all costs to resolve the problem.

Power Factor Considerations

Capacitors will be utilized to strive for unity power factor at the distribution bus in the substation. This should generally result in approximately +/-98% power factor at the transmission interface. Larger substation transformers may require additional capacitors inside the substation to correct for losses in the substation transformer and meet the +/-98% power factor level at the transmission interface. Additional information on capacitor application can be found in the Capacitor Application Guide.

Current Unbalance Considerations

Current percent unbalance is the maximum difference between any phase current and the average of the magnitudes of all three phase currents, expressed as a percentage of the average of the magnitudes of all three phase currents as shown below.

$$\%\ \text{Current Unbalance} = \frac{[\ (\text{Max. or Min. phase current})-(\text{average phase current})]}{\text{average phase current}} * 100\%$$

Unbalance should be kept to a minimum and not exceed 10% on any circuit or transformer.

Percent unbalance will be determined using load data at summer peak and if necessary, winter peak. Seasonal load variations may create current unbalances due to differing characteristics of customer loads. Proper load balancing provides an economic application of conductor and overcurrent protective devices, helps to maintain proper voltage balance, and reduces thermal stress on three phase equipment. The distribution planner should compare the cost of achieving the current unbalance guidelines against the cost of managing the performance of the distribution system with higher levels of unbalance.

Section 3

Reliability Planning Criteria

The planning criteria are used primarily to address the normal system capacity needs. However, the solutions are designed to support the overall reliability as well as outage recovery of the system. The following section addresses factors that enhance the reliability of the distribution system as opportunities arise.

Distribution Reliability

The goal of reliability improvement is reducing the actual number of outages that occur. This section of the planning criteria will focus on the considerations needed to reduce the number of outages by including reliability more prominently within the planning process.

AEP uses reliability indices as a measurement to evaluate how reliably it is providing service to its customers throughout the Operating Companies. Depending on the jurisdiction, the Operating Company may be required to report one or more indices to their state commission such as SAIDI, SAIFI, CAIDI, or $CEMI_5$. Distribution reliability has become more prominent in discussions with regulators and customers. For these reasons and the potential to improve reliability in conjunction with distribution system improvements, evaluating reliability should be included in the project planning process.

There are over forty reliability, asset management, and capacity strategies available to the operating company to utilize in an effort to improve their reliability. However, most Operating Companies limit their reliability focus, and budget to a smaller group. Reliability resources have historically been allocated to some or all of the following:

- Vegetation Management
- Pole Inspection Replacement/Reinforcement
- Inspection of OVHD Facilities
- Inspection of UG Facilities
- Lightning Mitigation
- Line Animal Guards
- Line Reclosers
- Sectionalizing
- Cutout Replacement

When developing a plan for the expansion or reinforcement of the distribution system, the planner needs to understand the reliability environment of the Operating Company and area under review. Some areas may need dramatic reductions in their SAIDI while other may be asked to “hold the line” and not invest significant resources. For example if an area has experienced excessive lightning related outages, based on Outage Management System data, then the addition of more surge arresters and grounds could improve reliability on the circuit(s) with little increased funding compared to the overall project cost.

Reliability data can be obtained from within C&DS by contacting either Business and Performance Management or Distribution Reliability Strategy and from the Operating Company by contacting the Reliability Manager. Additionally, within SmallWorld the planner can obtain graphical representations of outage data. This ability to review outage data in more detail provides the planner more complete information about the potential reliability impact of their plan.

Definitions for Reliability

C: Total number of *customers* served

CI: *Customer Interruption* is the number of customer service interruptions which lasted five minutes or longer.

CMI: *Customer Minutes of Interruption* is the number of minutes that a customer's electric service is interrupted for five minutes or longer

Outages: *Outages* is the number of service interruptions which lasted five minutes or longer.

There are four main indices that could be used for evaluation:

CAIDI: *Customer Average Interruption Duration Index* is an indicator of average interruption duration, or the time to restore service to interrupted customers. CAIDI is calculated by dividing the total system customer minutes of interruption by the number of interrupted customers. (CAIDI = CMI ÷ CI, also CAIDI = SAIDI ÷ SAIFI).

$CEMI_5$: *Customers Experiencing Multiple Interruptions (>5)* measures the percent of customers that have experienced more than five service interruptions. $CEMI_5$ is a customer count often shown as a percentage of total customers.

SAIDI:*System Average Interruption Duration Index* is a composite indicator of outage frequency and duration and is calculated by dividing the customer minutes of interruption by the number of customers served on a system.
(SAIDI = CMI ÷ C, also SAIDI = SAIFI x CAIDI).

SAIFI: *System Average Interruption Frequency Index* is an indicator of average service interruption frequency experienced by customers on a system. SAIFI is calculated by dividing the number of service interruptions by the number of customers served.
(SAIFI = CI ÷ C, also SAIFI = SAIDI ÷ CAIDI).

Outage Recovery

There is the recognized need to try and incorporate outage recovery to support the overall reliability of the system. Outage recovery addresses the mitigation of the outage by attempting to reduce the number of customers affected and/or the duration of the outage.

The ability to restore service to customers following an outage involving a substation or a complete circuit is greatest in urban areas where customer density has resulted in multiple substations with multiple circuit ties. In these urban areas, capacity is likely available to utilize these ties under most loading conditions. In suburban areas and small towns, there tend to be fewer substations and circuits. However, there is usually some ability to recover customers prior to the repair of damaged equipment or installation of a mobile transformer. In rural areas, where the customer density has not driven the need for multiple substations and circuits, there tend to be single substations serving a large area with radial circuits with no ties to other circuits. Therefore, rural areas generally experience extended outages until the damaged equipment is repaired or a mobile transformer is installed.

The goals of considering the Outage Recovery Planning Criteria as part of the overall distribution system planning criteria are:

- Preserve the ability to recover areas where sufficient circuit ties and capacity presently exist.
- Increase the ability to recover areas where circuit ties exist but there is limited capacity to utilize the ties during peak loading conditions.
- Increase the ability to recover areas with limited ties by building / strengthening ties between circuits.
- Increase the ability to recover rural areas by adding circuit ties and adding substation equipment.

These goals are one of the overall considerations in distribution system planning and do not dictate the ultimate plan.

Outage Recovery Areas

Urban Areas with a customer load density that is served by multiple stations with circuit ties that can be used to recover customers.

Goal -- Provide 100% recovery of customers with capacity redundancy inside the station and/or single tier switching at peak load for an outage of one station transformer or one circuit. Provisions should be made to restore the entire load with the remaining capacity without exceeding the emergency capability of any transformer winding, circuit, or any other limiting device. When 100% recovery of customers is not possible at peak load, a project can be submitted for prioritization.

Typically, efficient recovery occurs in areas where:

- Transformers of equivalent capabilities are utilized
- The load is spread evenly among the transformers

- Sufficient circuit ties exist or can be built to fully utilize the transformer capability
- Circuits are loaded to less than their capability during normal loading conditions to provide capacity for recovery of adjacent circuits or transformers.

Improvements in an area should work toward a system configuration that allows for the best use of available capacity.

Recovery in some areas may require switching that lasts longer than 2 hours. An example is an area served by a 42 MVA transformer where it may require transfers to multiple circuits to restore the entire load. If quicker recovery is needed, then a project for automated or supervisory control switching can be submitted for prioritization.

Some urban load areas have load densities that require larger transformer stations. These areas have loads including residential, commercial and industrial customers with multi-story buildings that can lead to load densities that require large capacity stations and many circuits. Recovery of these areas often requires capacity redundancy inside the station because the loss of a very large transformer may require more capacity than adjacent stations and circuits can provide.

This assumes loading transformers (or any other limiting devices) and circuits to their emergency capabilities during recovery with the understanding that a mobile transformer may be required if the loading situation will be for an extended period. The decision to install a mobile transformer will be made after consultation between the distribution planner, dispatch center, local operating personnel, and possibly a transformer equipment specialist. This decision will be based on several factors including expected loading level, duration, and transformer loss of life.

Suburban / Rural Partial Outage Recovery Areas with a customer load density that is served by multiple stations with circuit ties, but capacity and connectivity limitations result in some customers not being recovered until facilities are repaired or a mobile transformer is installed.

Goal -- Provide recovery of 80% of peak load with single tier switching for an outage of one station transformer or one circuit. When 80% recovery is not possible at peak load, a project can be submitted for prioritization. As load grows and additional capacity is added, opportunities to include improvements to upgrade the system's recovery capability should be considered.

> ***** *The mobile transformer installation time is anticipated to be 24 hours or less. Advance preparations should be made to reduce this time as much as possible. The following advance preparations are recommended:*
>
> - *Mobile transformer installation plans*

- *Dedicated mobile transformer connection facilities in the station*
- *Adequately sized mobile transformers are strategically located*

.

Rural / Mobile Transformer Dependent Areas with a customer load density that is served by stations with limited or no circuit ties that result in most customers not being recovered until facilities are repaired or a mobile transformer is installed.

Goal – Reduce dependence on mobile transformers. When full recovery is not possible, then limit the load at risk to available mobile transformer size. However, if the available mobile transformer is not capable of recovering the entire load at risk, a project can be submitted as a normal overload capacity project. Mobile transformer recovery is expected to be available in less than 24 hours*.

> ***** *The mobile transformer installation time is anticipated to be 24 hours or less. Advance preparations should be made to reduce this time as much as possible. The following advance preparations are recommended:*
> - *Mobile transformer installation plans*
> - *Dedicated mobile transformer connection facilities in the station*
> - *Strategically located, adequately sized mobile transformers*

Distribution Circuit Utilization Considerations

Circuits should be designed with a layout that will ultimately include ties to at least two other circuits. This implies that the planner attempt to load a circuit to no more than 2/3rds of its capacity rating in order to achieve zero load a risk for N-1 station transformer contingencies and to allow attainment of clearances using adjacent sources. The following operational factors can influence a circuit system’s ability to absorb load during planned and unplanned outages.

Load Unbalance

Planning guidelines specify a percentage unbalance to not exceed 20% on any circuit and should be managed to 10% or less.

Example:

Phase A: 100 amps, Phase B: 100 amps, Phase C: 133.35 amps equates to a 20% unbalanced condition. If the conductor ampacity rating (100 deg C rating) equals 120 amps, this example would result in a loading condition of over 111% of capacity rating on the high phase. Unbalanced limitations should be considered when calculating reserve margin.

Abnormal Switching Conditions

Routine maintenance or construction may require clearance of a particular station transformer or circuit. Care should be given to assess the vulnerability of these situations so that areas have sufficient reserve capacity to cover most contingencies. In other words, a good design should accommodate N-1 conditions (single element out) and attempt to minimize the impact of an N-2 or greater (where necessary) condition. Special consideration should be given to areas with Alternate Feed Service (AFS) loads.

Lack of Sufficient Ties

The placement of circuit ties is a critical element when considering the reliability of a distribution system. Some circuit ties may be loaded too heavily under normal circumstances or tied to a station with a limited available capacity. More than two ties may be necessary to work around these situations. Also, geographic (accessibility) concerns and circuit tie proximity can influence multiple outage probability and influence response times to outages. Care should be given to work these switching scenarios into the design.

Tapered Conductor Sizes

A tapered conductor size is common due to economic reasons when a circuit migrates from source to end as the connected load decreases. In a gridSMART world where distributed resources may tie in at any location, a new approach may need to be considered. Larger and more consistent conductor sizes should be favored to take advantage of these resources for islanding and contingency planning in general in order to optimize recovery and improve voltage profiles for various resource availability scenarios.

Low Voltage Concerns

Length of circuits and voltage class influences circuit stiffness and an area's ability to be protected and serve load. Lengthy circuits will typically have more voltage regulation points and in general are less reliable relative to other solutions due to higher exposure distances. Circuit designs should take these limitations into account when evaluating contingency scenarios.

Non-uniform Load Distribution on Circuit

An ideal circuit has load that is uniformly distributed which allows standard solutions to reactive load planning and circuit tie design. Non-uniform loads will cause circuits to behave differently and may require more localized solutions for contingency optimization.

Conductor Size too Big

Studies have shown that in general larger conductor sizes should be utilized to the first junction point in order to minimize circuit losses as the larger conductor size is justified by the loss avoidance. The challenge becomes planning from a utilization perspective. If a conductor size is too big, it may place a system at risk due to normal loading when there is too much reliance on a particular circuit. If a highly loaded high capacity circuit is lost during a contingency, adjacent circuits may not be able to recover its load –or- it may be relied upon to cover too many contingencies. Care should be given to balance conductor size with circuit availability to optimize station transformer sources and allow for diversity of circuit resources.

In summary, the aforementioned general considerations should be checked when laying out a new or modified distribution circuit plan. Each situation is unique; however, the ultimate goal should be to optimize reliability in a cost effective manner. It should be noted that in order to achieve a system that is both maintainable and reliable, projects should be considered before capacity rating limits are exceeded.

Example Solutions

The following are example solutions to address the different outage recovery areas.

Transmission Solutions
- Provide a second transmission source for radial lines (Upgrade to a loop system)
- Add sectionalizing to existing looped transmission lines.
- Add SCADA / Automation to existing looped transmission lines.

Station Solutions
- Add a new station
- Add transformer(s) in a single bank station
- Use 4 single-phase transformers with 1 unit as an “in place” spare
- Add new circuit position
- Add utility or customer owned distributed generation

Circuit Solutions
- Create loops between circuits
- Upgrade capacity of existing loops between circuits
- Add Distribution Automation to circuits with loop capability
- Add SCADA to long radial circuits that cannot feasibly be looped
- Add new circuit position
- Add utility or customer owned distributed generation

General Considerations for Outage Recovery

If a “Normal Capacity” project becomes necessary, the planner should consider additional improvements to upgrade the ability to recover the area. These additional improvements should be targeted to address the issues that have historically caused high impact outages and/or issues that are anticipated to be a high risk for causing high impact outages in the near future.

When a transformer is projected to be loaded to a level that cannot be recovered by one mobile transformer that is normally available to the area after all available transfers are completed, then a project to provide load relief or to add capacity can be submitted for prioritization.

The distribution planner may also consider limiting the planned normal loading to 90% of the transformer's capability. This would limit the risk of overloads where no recovery or load transfer is possible and would also drive projects that enhance recoverability sooner.

Prioritization of Outage Recovery Projects

The following factors should be considered in prioritizing outage recovery projects:

- Projects should be prioritized with other projects in a criteria category as defined above. The goal of the Distribution System Planning group should be to offer a selection of the highest value projects in each category for each jurisdiction. Operating Company reliability strategy decisions will influence funding levels for the different criteria categories.
- Consider the amount of load at risk during an outage. Load at risk is defined as the load that remains out of service for an outage after all possible load transfers have been completed. Load transfers are normally limited to single tier switching but can include additional tiers if switching can be done safely. Results of additional switching should maintain proper voltage and not place additional facilities at risk of failure.
- Evaluate the general reliability of the affected area.
- Calculate the reduced customer outage minutes (COM) and the cost for the reliability gained ($/COM reduced).
- Other relevant parameters

Definitions for Outage Recovery

Emergency Capability – Substation Transformers

AEP Distribution System Planning utilizes the EPRI PTLoad program and AEP Station Design Engineering Standards SS-780001 and SS-780002 to calculate normal and emergency capabilities for transformers.

The normal capability is based on an ambient temperature cycle and peak load cycle for the 24-hour peak conditions. The emergency capability is based on the same ambient temperature and load cycle but allows higher transformer temperatures.

The normal and emergency capabilities should be in the Distribution Load Forecast Database and available to operating personnel directing the recovery operation. These capabilities should include any other limiting factors up to the distribution circuit breaker.

Emergency Capability – Conductors and Other Devices

Conductors and other devices may be the limiting factor in the recovery switching for an area. When studying an area for outage recovery these limiting factors must be considered. The capabilities for the circuits should include any limitations on the main circuit. Possible limitations include but are not limited to the circuit breaker, relay settings, circuit regulators, switches, and underground or overhead conductor.

Distribution Automation

Distribution automation is a combination of field installed hardware and software managed operations logic. The purpose is to automatically restore in less than 5 minutes un-faulted sections of circuits that have lost power due to a fault in an upstream source section. Adequate voltage, capacity, and over-current protection must remain for the reconfigured system. Utilities across the country are investing more in loop schemes and distribution automation. Distribution automation is one tool for improving reliability. Application of distribution automation can significantly improve reliability in an area (up to 50%), and in many cases will achieve a targeted reliability performance level. The cost of applying distribution automation is mid-range with other improvement tools if sufficient circuit ties and recovery capacity are available. The cost of this tool increases if infrastructure improvements are needed. The decision to utilize distribution automation can be made by comparing its cost benefit ratio to that of other solutions for improving the area's reliability. Distribution automation is also one of the elements found within the gridSMART^{SM} initiative. Additional information regarding distribution automation can be found in Section 4 of this document.

Section 4

Alternative Concepts

In Section 1 of this document, the philosophy of planning for the most consistent orderly expansion and reinforcement of the distribution system is discussed. The following section addresses alternative concepts that the planner should be aware of that can impact his review of the distribution system.

The following alternative concepts are discussed in this section:

- **gridSMART^{SM}**
    - Distribution Automation
    - Volt-Var Management
    - Energy Storage
    - Home Area Network (HAN)
    - Advanced Metering Infrastructure (AMI)
- **Asset Renewal**
- **Distributed Generation**

gridSMART^{SM}

gridSMART is a suite of customer programs and advanced technology initiatives that are intended to improve reliability, energy efficiency, and service quality. Distributed Automation, Volt-Var Management, Energy Storage, HAN, and AMI are the main gridSMART elements that can impact a planning review of the distribution system. These elements are described below:

gridSMART^{SM} Distribution Automation

Distribution Automation (DA) can refer to many technologies, but is most commonly associated with schemes involving switching devices that automatically reconfigure to restore service to customers affected by a sustained outage event. This "self healing" grid concept typically utilizes automated switches or reclosing devices on the line and a control scheme in one of the following forms:

<u>Distributed Intelligence</u>

Distributed Intelligence is associated with DA schemes where the resident logic for restoration resides at each field switch or recloser control. This logic communicates present state information to each control (peer to peer) so that when a fault occurs, each control knows loading conditions, switching states, and fault location. The intelligence then restores customers based on available capacity and user-defined preferences. These systems are designed to provide relatively fast restoration times even if SCADA communications are unavailable. Distributed Intelligence schemes are the most reliable and easy to maintain form of DA and are not dependent on a single communication system.

<u>De-centralized Intelligence</u>

De-centralized Intelligence DA uses a master/slave type of control where the master controller physically resides at a station head-end point(s). In this type of scheme, the restoration logic is programmed into the master controller and then communicated out to the field devices. As is the case with Distributed Intelligence applications, this scheme will continue to work if SCADA is unavailable; however, the system goes unavailable if the master controller is out of service. The advantage to this type of system is that less expensive field devices (dummy devices) can potentially be used in the interface. This system also provides a mechanism for very precise restoration control and fast restoration speeds depending on communication technologies deployed. De-centralized Intelligence requires available resources and expertise to program and maintain the logic in the DA controller. It may require more support resources than a Distributed Intelligence based system.

<u>Centralized Intelligence</u>

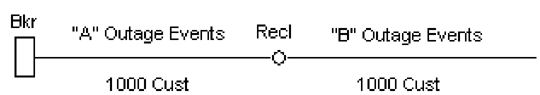
Centralized Intelligence also utilizes a master/slave type of control where the master controller is server based software that typically resides centrally at the DDC. In a Centralized DA scheme, outage and load information is modeled automatically, and an optimized command sequence to isolate outages and restore customers is deployed to field devices via D-SCADA interface points at station level RTUs. This type of system is theoretically the most flexible DA scheme available, but the most unreliable. If the centralized software is unavailable, total DA is nonfunctional. Restoration times will also be much slower than with Distributed Intelligence or De-centralized Intelligence DA schemes.

Benefits of Distribution Automation

SAIFI Impact Considerations:

A traditional main-line sectionalization scheme will utilize a station feeder breaker and a minimum of one recloser out on the line. Figure 1 illustrates this concept in its most basic form with a single breaker/recloser combination on a feeder that has uniformly distributed customers on both sides of the line recloser. Assumption: all outages are "sustained" outages.

Figure 1 (traditional sectionalization)



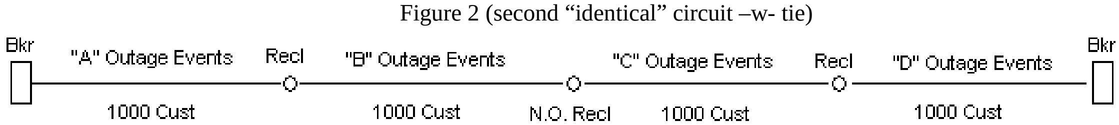
If A=2, B=0: SAIFI = (2 x 2000) customer outages / 2000 customers served = 2.00

If A=1, B=1: SAIFI = [(1 x 2000) + (1 x 1000)] / 2000 = 1.50

If A=0, B=2: SAIFI = (2 x 1000) / 2000 = 1.00

Traditional sectionalization provides a SAIFI range of between 1.00 and 2.00 depending on where the outage events are located.

Figure 2 (second "identical" circuit –w- tie)



In Figure 2, a second identical circuit has been added with a normally open tie point; all points using reclosers. Considering the new two circuit system and mirroring outage events, the SAIFI numbers remain unchanged. If DA is now added such that one circuit can switch sections to another circuit, the resulting SAIFI benefit is as follows for the same sustained outage events:

If A=2, B=0, C=0, D=2: SAIFI = [(2 x 1000) x 2] / 4000 = 1.00

If A=1, B=1, C=1, D=1: SAIFI = [(2 x 1000) x 2] / 4000 = 1.00

If A=0, B=2, C=2, D=0: SAIFI = [(2 x 1000) x 2] / 4000 = 1.00

In summary, DA can provide a SAIFI reduction benefit of up to 50% when considering a uniformly distributed customer population and two circuit system. SAIFI reductions of 60% or greater can be achieved by adding additional DA sectionalization points and circuit ties. Additional circuit ties can also make the system more capable of handling load transfers automatically during peak loading conditions. It should be noted that if a DA scheme includes the station breaker, additional benefit can be achieved when considering transmission side outages. In this scenario, all of the customers could be restored automatically from an adjacent source when recovering from a station outage event.

SAIDI Impact Considerations:

Customer Minutes of Interruption (CMI) are reduced as sustained outages are avoided with DA restoration schemes. In order to accurately quantify CMI benefits due to a DA operation, one must estimate the avoided time associated with manually patrolling and isolating the outage event. In urban type areas, this number can conservatively be estimated by multiplying the sustained outages avoided due to DA operation times 60 minutes. In areas that tend to have longer restoration times, such as in mountainous regions, the avoided patrol and manual switching time multiplier could be considerably more than 60 minutes. One should look at area CAIDI values to properly estimate practical limits for the avoided patrol and manual switching time multiplier.

gridSMART^{SM} Volt-VAR Management

Volt-Var management systems (i.e. Integrated Volt-Var Control) are used to improve energy efficiency, reduce energy consumption and demand on the distribution system by lowering system voltage. It is anticipated that, for every 1% circuit voltage reduction, a 0.7% - 1% demand reduction may be realized. Energy reduction corresponds directly to demand reduction. Volt-Var management systems can also improve system power factor in most instances and be a cost effective, short term alternative solution to a large distribution capital improvement project.

In the pursuit of demand response goals through lowered circuit voltages, primary voltage levels must not drop below the minimum 117 volt limit discussed in Section 2 of this document. Therefore, it may be necessary to first narrow (flatten) voltage variations throughout the whole circuit before lowering the voltage by the desired amount. Load balancing, the addition of line capacitors and voltage regulators may be required to flatten the circuit voltage profile.

Maintaining primary voltages within the voltage range stated in Section 2 requires voltage regulators, line capacitors and other gridSMART technologies to work together to control circuit voltage on a near real time basis. Capacitor bank sizes may need to be reduced, and the number of switched banks increased, in order to get tighter voltage control. Care must be given to properly consider voltage regulator sizing and placement to maintain flexibility in operation during normal and contingency conditions which may include future switching automation.

gridSMART^{SM} Energy Storage

Energy storage has been used by electric utilities for many years in different formats to meet various needs. Pumped hydroelectric storage is an early example of meeting bulk electricity storage needs. Flywheels and batteries are other energy storage devices that have been used to improve reliability and power quality. The format, size, and location must be suitable for the requirements of the application.

Although advancements have been noted in most storage devices, battery technology is advancing, in part, due to the increasing demand for electric vehicles. Electric utilities have increased the applicable uses of storage devices on their power grid by integrating them into intelligent grid management such as gridSMART^{SM}.

Storage may be applied on the distribution system to realize one or more of the following applications:

- Capacity relief; peak load shaving
- Improved asset utilization through load leveling
- Increased reliability by reducing momentary and permanent interruptions
- Reactive power compensation
- Improved power quality through flicker and harmonic mitigation
- Integration of local renewable generation
- Plug-in electric vehicle (PEV) charging

- Increased efficiency for interfacing to DC systems such as PEV's or solar distributed generation.

The aggregated impact of storage on distribution may provide the following system level benefits:

- System stability; islanding load in lieu of load-shedding
- Frequency regulation
- Energy arbitrage
- Buffering bulk renewable generation
- Potential environmental benefits by reducing emissions during critical air quality periods

The available energy and power capacity of an energy storage system depends on its intended application. The type of storage, such as battery chemistry, is dependant on the cycling requirements to satisfy the application. Physical size and site needs are driven by the power and energy requirements as well as the type of storage selected. Example formats of energy storage are the sodium sulfur (NaS) battery, Community Energy Storage (CES) system, and flywheel technology.

<u>Station Scale Applications (NaS Battery, other)</u>

The NaS (Sodium / Sulfur) battery technology is suited for multi-MW, multi-hour applications. As compared to other battery technologies, the NaS battery has higher energy density and efficiency as well as a longer life expectancy. This format has been applied for peak shaving and islanding. NaS units have been installed at existing or new station locations on the distribution system. In combination with a Distribution Automation scheme, dynamic islanding can be implemented to provide additional reliability. The appropriate size and cost benefits need to be considered when evaluating storage options.

Future station scale storage will likely use battery chemistries other than NaS including Zinc Bromide, Lithium Ion, Nickel Metal-hydride. Modularized units that can be readily relocated are becoming available.

<u>Community Energy Storage</u>

Community Energy Storage (CES) consists of small battery storage units connected to the secondary of transformers serving residential or small commercial loads. A large number of these units will be aggregated regionally and controlled as a fleet. The individual CES Units are designed to manage their individual charge and discharge activity in response to regional needs at the circuit, station, or system level. CES units are also designed to be maintenance free. They have comparatively high efficiency and long life expectancy with good cycling characteristics. CES will provide capacity, efficiency, and reliability benefits for a distribution system through the following key functions:

Grid functions (aggregation of fleet):

- Load leveling, peak shaving at the station level
- Power factor correction at the station level (reactive support)

- Ancillary services (frequency regulation, energy arbitrage)

Local functions (individual units):

- Standby power for customers connected locally
- Local voltage control (flicker and harmonic mitigation)
- Integration with renewable resources

Flywheel Technology

A Flywheel is a device that stores kinetic energy in a rotating mass connected to a motor/generator. By operating at a high spin rate, a great deal of energy can be stored and made available with a rapid response rate. Currently, flywheel designs show they can provide a capacity up to 20MW and advancing technology may increase their capability. The response time to reach their rated power has been measured to be within four seconds. Flywheels are commonly designed to provide their full load power for 15 seconds but others have also been capable of running at their required power levels for 15 minutes or longer. Therefore, this technology is suitable for large power applications demanding rapid response at comparatively short durations, such as the following:

- Frequency regulation
- System stability
- Buffering of renewable generation
- Reliability from power disturbance ride-through capability

As compared to other storage technologies, flywheels offer comparable efficiency and a life expectancy of approximately 20 years with proper maintenance.

gridSMART^{SM} Home Area Network (HAN)

Today, customers can only determine energy usage after the fact through their monthly bill. A Home Area Network (HAN), located within customers' homes, will allow customers to conserve energy and save money through increased information and control of their electric usage. The HAN can provide real-time and historical electrical usage, providing the customer with the knowledge and opportunity to control usage, conserve energy and save money. Programmable communicating thermostats, smart appliances, and load control switches are some of the components that may be found within a HAN.

A programmable communicating thermostat (PCT) in a home or businesses has the ability to receive electrical energy consumption data from the meter, store the data, and provide the customer with near real-time and historical energy usage. The PCT can receive price signals from smart meters and be programmed to regulate temperature accordingly, allowing the customer to regulate their indoor temperature in response to daily or seasonal electric price fluctuations while maintaining an acceptable level of comfort. Advanced PCTs available today also have the capability to cycle air conditioning on and off upon receiving a critical peak signal from the smart meter.

A Load Control Switch (LCS) is a device installed ahead of a major electrical appliance that can either turn the appliance on or off or cycle the appliance on and off as in the case of an air conditioning unit. For customers that choose a direct load control or interruptible tariff, the LCS would receive commands from the smart meter, respond accordingly, and send a signal back to the meter to confirm action has been taken.

Smart appliances may someday be used to connect to a utility's advanced metering infrastructure (AMI). The goal of using smart appliances is to provide increased customer energy awareness. Being aware of their energy usage, customers can potentially optimize their usage to reduce their energy bills and reduce their demand. The smart appliance may be able to respond to pricing and load control signals so that customers can choose when to operate them.

In addition, HAN enables AEP operating companies to provide the customer pricing options including time-differentiated rates. Data collected by the HAN can help AEP operating companies to shape future pricing programs to suit customers' needs. As customers save money by shifting load to off-peak hours, it helps AEP operating companies to reduce demand and potentially defers the need for new generation, transmission, and distribution infrastructure.

gridSMART℠ Advanced Metering Infrastructure (AMI)

The Advanced Metering Infrastructure program is the foundation for a system that will provide information regarding consumers' electrical usage patterns as well as outage and power quality data. The AMI program will replace electric meters currently used with those of an advanced technology, designed to allow customers more control of their use of electricity. The customers will be empowered to conserve energy. Also, as lower time-of-use pricing is available, customers could increase their savings by evaluating their usage patterns to determine if they can post-pone their electrical use to a time in the day when a lower price rate is offered. AMI will also help improve service reliability by notifying AEP of an outage and determine its proximity by the location and number of meters affected.

Engineers can leverage AMI technology to build more accurate load flow models. This will expand alternatives when studying normal capacity as well as outage recovery planning scenarios. System efficiencies can also be modeled and analyzed using interval data from AMI technology. Another use for AMI data is the building of near real-time models that can be used by Operations to shift loads between stations/circuits with different load profiles, resulting in better utilization of assets.

Asset Renewal

The aging infrastructure of the distribution system is an increasing concern. Aging assets are prone to failure at an increasing rate.

An AEP objective is to review, analyze and identify:

1. Assets in service beyond their expected operational life

2. Assets in service beyond their depreciable life

3. Assets with reliability and maintenance performance below expectations

Once the above assets have been identified, an asset renewal strategy can be determined. Projects to address aging infrastructure may be submitted by themselves. However, it may be beneficial to integrate asset renewal with other projects (i.e. targeted reliability improvements, distributed generation, energy efficiency enhancements, gridSMART, sustainability, and traditional capacity improvement projects). By combining asset renewal with capacity improvement projects, synergies may be obtained such that the age of assets can become part of the prioritization process for the long range distribution capacity workplan.

Distributed Generation

Distributed Generation (DG) refers to any form of generation that is interconnected to AEP distribution facilities either at the station bus or on the line. Traditional forms of generation consist of rotating machinery driven by a prime mover where power delivered is a function of mechanical power supplied. Synchronous generators have the ability to operate independently from the power grid whereas induction generators require grid reactive support for excitation.

Non-traditional forms of generation typically produce power in a direct current output connected to the utility grid via inverter-based technology. Solar arrays, wind turbines and fuel cells are examples of non-traditional DG resources that can supply power to the distribution grid. Wind and solar power are classified as renewable energy resources and are intermittent in nature. Renewable energy resources can be coupled with storage technologies; i.e., Community Energy Storage (C.E.S.) batteries, to improve availability during critical loading periods.

Stand alone generation solutions can be used in load reduction schemes or for islanding areas during outage isolation events. <u>It is important for the planner to consider the impact of existing generation when producing load forecasts. The planner should also consider DG as an alternative solution to mitigate projected overloads on the distribution system to defer more expensive capacity improvement projects</u>. It should be noted that unless a DG installation has been thoroughly analyzed and designed for islanding capability, the installation would not be allowed to be used in islanding mode beyond the point of common coupling (PCC).

All forms of distributed generation must comply with the appropriate state utility commission terms and conditions.

Definitions

Abnormal System Condition	A single component outage and/or temporary reconfiguration of the electrical system.
AMI	Advanced Meter Infrastructure - includes smart meters, associated communication and information technologies that exchange data about usage and load, control other devices, and can be remotely connected, disconnected and programmed.
Area EPS	An EPS that serves Local EPSs.
C	Total number of customers served
CAIDI	Customer Average Interruption Duration Index is an indicator of average interruption duration, or the time to restore service to interrupted customers. CAIDI is calculated by dividing the total system customer minutes of interruption by the number of interrupted customers. (CAIDI = CMI ÷ CI, also CAIDI = SAIDI ÷ SAIFI)
$CEMI_5$	Customers Experiencing Multiple Interruptions (>5) measures the percent of customers that have experienced more than five service interruptions. $CEMI_5$ is a customer count often shown as a percentage of total customers.
CES	Community Energy Storage - consists of small battery storage units connected to the secondary of transformers serving residential or small commercial loads.
CI	Customer Interruption - is the number of customer service interruptions which lasted five minutes or longer.
CMI	Customer Minutes of Interruption - is the number of minutes that a customer's electric service is interrupted for five minutes or longer
Continuous Load Rating	The maximum amount of load, expressed in either amperes or apparent power (kVA or MVA), that a piece of electrical equipment can carry indefinitely.
Criteria	Standards on which a judgment or decision can be based
DDC	Distribution Dispatch Center

Definitions

Distribution Area	A collection of substations in a given geographic area that are grouped to readily identify the area, such as a portion of a division, etc. Distribution areas may or may not be the same as areas used for generation, bulk transmission, etc.
Distribution System	An electrical system operated at a nominal voltage, which at AEP is up to but not including 46 kV phase to phase. For the purposes of these criteria, the distribution system includes all substation equipment operated in this voltage range, including the substation power transformer.
Dummy Devices	gridSMART^{SM} – enabled field devices, such as motor-operated switches or reclosers, where the intelligence for outage restoration resides at a Centralized or De-centralized location.
Dynamic Islanding	Ability of a distributed resource to island various numbers of customers such that the supported load level matches the available resource capacity.
Effective Substation Rating	The continuous load rating of a substation or portion of a substation that is determined by the capability of a component whose loading limitation is lower than the rating based solely on the substation transformer thermal capability.
Emergency Capability Rating	The current, voltage or power limits to which a component can be loaded beyond the normal capability or nameplate rating with some acceptable loss of service life. A specified number of consecutive hours or amount of cumulative time is associated with the use of this capability / rating.
EPS	Electric Power System
Fault	Any failure which interferes with the normal flow of current, for example, a short-circuit, a broken wire, an intermittent connection, etc.
Flicker	A momentary change in voltage on a portion of the distribution system caused by a transient condition.
Good Engineering Judgment	The practice of making decisions or choosing values based on sound engineering knowledge and the best available information at the time the decision was made. Such decisions are intended to provide safety, reliability and/or economies where there is insufficient information to produce an otherwise unequivocal solution.

Definitions

Good Utility Practice	Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts, which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others.
Interrupting Rating	The highest current that a circuit-breaking device can interrupt at rated voltage.
Islanding	Load served from a section of circuit or portion of a grid that is separated from its normal source of power due to a power system disturbance such as a power outage or system voltage fluctuation. This isolated section is transferred to a distributed resource(s) until the normal source of power is restored.
Limiting Factor	The equipment component of a substation that defines its Effective Substation Rating. A circuit will also have a limiting factor that defines its effective capability.
Load at Risk	The amount of load that cannot be adequately served during a single component outage by utilizing all reasonable efforts to switch and restore load immediately following the outage. For the purpose of this definition, load can be adequately served if it falls within the emergency capability of the device used in the outage recovery and the voltage can be maintained within prescribed voltage limits.
Load Bonus	Extra capacity permitted for a voltage regulator due to a decrease in regulation range (smaller range than +/- 10%).
Local EPS	An EPS contained entirely within a single premise or group of premises.
Long Range	Typically beyond 3 years
Nameplate Rating	The current, voltage and power limits of a component, which are specified on the manufacturer's equipment nameplate.
NaS	Sodium-Sulfur – a battery chemistry, energy storage technology
Non-coincident	Occurring at different times, or for planning purposes at different hours.

Definitions

Normal Capability	The maximum thermal capability of a substation transformer expressed in kVA or MVA for a specified time period and some acceptable loss of service life. This capability is typically higher than the nameplate rating when subjected to a pattern of varying demand during varying ambient temperatures. Using the present industry standard software and ANSI/IEEE standards, this capability is calculated by extrapolating data from the manufacture's heat run test report and nameplate data or from actual measured operating temperatures.
Normal System Condition	Operational status of the normal system configuration where all components of the system are in service and performing as intended.
Operating Company	A subsidiary of the AEP system, specifically Appalachian Power (APCO), AEP Texas (AEP Texas Central and AEP Texas North), AEP Ohio (Columbus Southern Power-CSP and Ohio Power-OPCo), Indian Michigan Power (I&M), Kentucky Power (KPCO), Kingsport Power (KgPCo), Public Service Company of Oklahoma (PSO), Southwestern Electric Power Company (SWEPCO), and Wheeling Power (WPCo).
Point of Common Coupling (PCC)	The point where a Local EPS is connected to an Area EPS
Risk	The chance that as a consequence of specific planning decisions an outcome may be lower than expectations either in terms of system performance, reliability, or finances.
RTU	Remote Terminal Unit. Used to provide SCADA communication to station and/or gridSMART^{SM} – enabled field devices.
SAIDI	System Average Interruption Duration Index is a composite indicator of outage frequency and duration and is calculated by dividing the customer minutes of interruption by the number of customers served on a system. (SAIDI = CMI ÷ C, also SAIDI = SAIFI x CAIDI)
SAIFI	System Average Interruption Frequency Index is an indicator of average service interruption frequency experienced by customers on a system. SAIFI is calculated by dividing the number of service interruptions by the number of customers served. (SAIFI = CI ÷ C, also SAIFI = SAIDI ÷ CAIDI).

Definitions

Short Range	Typically within 3 years.
Single Tier Switching	The operation of substation and distribution circuit switches to restore electrical power during an outage where each segment of the system without power under normal configuration is switched to immediately adjacent sources without first having to transfer load that was previously not affected by the outage.
Station Head-End Points	Substation locations where gridSMART^{SM} information, such as switching automation or Volt-VAr information, transitions from the field to the SCADA system interface.
Steady State	A condition where magnitudes of voltage and current do not vary over an arbitrarily long interval of time.
Summer	The months of May through October.
Transient	A temporary condition on the electric distribution system characterized by abrupt changes in power flow resulting in voltage and current fluctuations.
Winter	The months of November through April.

DATA REQUEST

KPSC 8_15 Refer to Vaughan Rebuttal Testimony in general. Provide Kentucky Power's distribution system planning criteria used for determining whether equipment requires replacement for thermal violations.

RESPONSE

Please see KPCO_R_KPSC_8_14_Attachment1 for the requested information. This document outlines Kentucky Power's guidelines and criteria, primarily in section 2, for replacing equipment due to thermal violations.

Witness: Everett G. Phillips

DATA REQUEST

KPSC 8_18 Refer to the Rebuttal Testimony of Brian K. West, page 15. Provide the screening criteria Kentucky Power uses to evaluate interconnecting facilities, and include a detailed explanation of how each screening criteria is tested and the associated assumptions.

RESPONSE

Kentucky Power evaluates applications for interconnection of Distributed Energy Resource (DER) capacity in a tiered approach to expedite the Company's review and approval of applications. Upon verification of receipt of a complete application, all applications are screened by the local Distributed Generation Coordinator to determine if additional screening may be necessary. The content of that screen, including explanation of the review question details, are as follows:

Is the Total DER Nameplate AC Capacity greater than or equal to 25 kW?

- This screening question is intended to identify systems greater than 25 kW of generating potential which may on their own lead to voltage imbalances, high fault current contributions, or overvoltage.

Does the maximum generating capacity (kW-AC) of all DER systems attached to the service transformer meet or exceed 100% of the rated Transformer Apparent Power (kVA)?

- This screening question is to identify applications where the aggregate generating capacity would meet or exceed the equipment rating for the transformer, requiring additional review and potential upgrade to equipment.

Is the DER system or customer service 3-phase?

- This screening question is to identify 3-phase systems and services so that they can be further evaluated to identify phasing imbalance, phase-to-phase matching, and sufficient grounding between the primary and secondary side

Is the DER system non-Inverter based?

- This screening question is to identify DER systems that may contribute KVAR to the system or have attributes consistent with rotating generators such that they would require additional review by an engineer to determine potential system impacts.

Is the DER system interconnecting to a Networked Circuit?

- This screening question is to identify customers served by networked secondary circuits which must be reviewed by network engineers to determine any potential system impacts.

Is there more than 1,000 kW (AC) of DER Capacity installed or approved to install (including this application) on the interconnected distribution circuit?

- This screening question is to identify application which in aggregate with all other in service and approved applications would potentially exceed a minimum penetration threshold for the interconnected distribution circuit.
- If an application passes the above screens ("no" answers to all of the above questions), the application is approved without additional technical screening required. If any of these questions are answered in the affirmative, a Level 1 screen is performed, the content of that screen, including explanation of the review question details, are as follows:

Is the aggregate generation capacity, including the capacity of the Project, 15% or less than the peak load on the smallest portion of the primary distribution circuit that could remain connected after operation of any sectionalizing devices?

- This screening question has been adapted from the Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedure (SGIP), section 2.2.1.2, and is part of the Kentucky Interconnection Guidelines, Appendix A as part of Administrative Case No. 2008-00169 for Level 1 review conditions.

If the Project is to be interconnected on single phase shared secondary conductors, is the aggregate generation capacity, including the capacity of the Project 20 kVA or less?

- This screening question has been adapted from the FERC SGIP, section 2.2.1.7, and is part of the Kentucky Interconnection Guidelines, Appendix A as part of Administrative Case No. 2008-00169 for Level 1 review conditions.

If the Project is to be interconnected on a center tap neutral of a 240 volt service, will its addition result in 6 kVA or less imbalance based upon the nameplate rating of the service transformer?

- This screening question has been adapted from the FERC SGIP, section 2.2.1.8, and is part of the Kentucky Interconnection Guidelines, Appendix A as part of Administrative Case No. 2008-00169 for Level 1 review conditions.

Is the point of common coupling on a radial circuit?

- This screening question has been adapted from the FERC SGIP, section 2.2.1.3, and is part of the Kentucky Interconnection Guidelines, Appendix A as part of Administrative Case No. 2008-00169 for Level 1 review conditions.

Is the aggregate generation capacity on the circuit, including the capacity of the Project, 5% or less than the total circuit annual peak load as most recently measured at the substation?

- This screening question has been adapted from the FERC SGIP, section 2.2.1.2, and is part of the Kentucky Interconnection Guidelines, Appendix A as part of Administrative Case No. 2008-00169 for Level 1 review conditions.

Is the aggregate short circuit contribution ratio of all generation on the distribution circuit, including the Project, 0.1 or less?

- This screening question has been adapted from the FERC SGIP, section 2.2.1.4, and is part of the Kentucky Interconnection Guidelines, Appendix A as part of Administrative Case No. 2008-00169 for Level 1 review conditions.

If the Project is to be interconnected on a shared secondary, is the Project's short circuit contribution 2.5% or less than the interrupting rating of the Project's interconnection system?

- This screening question has been adapted from the FERC SGIP, section 2.2.1.5, and is part of the Kentucky Interconnection Guidelines, Appendix A as part of Administrative Case No. 2008-00169 for Level 1 review conditions.

Is the Project in violation of any applicable provisions of IEEE 1547?

- This screening question is part of the Kentucky Interconnection Guidelines, Appendix A as part of Administrative Case No. 2008-00169 for Level 1 review conditions. Non-certified systems can require additional study to determine impacts to the Area Electric Power System.

Does the Project require any system/facility upgrades or modifications to support the interconnection?

- This screening question has been adapted from the FERC SGIP, section 2.2.1.10, and is part of the Kentucky Interconnection Guidelines, Appendix A as part of Administrative Case No. 2008-00169 for Level 1 review conditions.

Witness: Brian K. West

Witness: Jacob H. Crocker

VERIFICATION

The undersigned, Jacob H. Crocker, being duly sworn, deposes and says he is a Customer Program Service Analyst for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Jacob H. Crocker

State of Indiana	)	
	)	Case No. 2020-00174
County of Allen	)	

Subscribed and sworn before me, a Notary Public, by Jacob H. Crocker this 26th day of February, 2021.

Regiana M. Sistevaris Digitally signed by Regiana M. Sistevaris
Date: 2021.02.26 07:21:01 -05'00'

Regiana M. Sistevaris, Notary Public

My Commission Expires: January 7, 2023

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E-Signature Summary

E-Signature 1: Everett Phillips (G)
February 19, 2021 07:12:49 -8:00 [4E1FF737C837] [167.239.2.87]
egphillips@aep.com (Principal) (Personally Known)

E-Signature Notary: S. Smithhisler (SRS)
February 19, 2021 07:12:49 -8:00 [DFBC92D9A209] [167.239.221.83]
srsmithhisler@aep.com
I, S. Smithhisler, did witness the participants named above electronically sign this document.

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VERIFICATION

The undersigned, Everett G. Phillips, being duly sworn, deposes and says he is Vice President of Distribution Region Operations for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Everett Phillips
Signed on 2021/02/19 07:12:49 -8:00

Everett G. Phillips

STATE OF OHIO)
) Case No. 2020-00174
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Everett G. Phillips, this 19th day of February 2021.

NOTARY PUBLIC
STATE OF OHIO
Sarah Smithhisler
Commission # 2019-RE-775042
Electronic Notary Public
State of Ohio
My Comm Exp. Apr 29, 2024
Notary Stamp 2021/02/19 08:12:49 PST DFBC92D9A209

S Smithhisler
Signed on 2021/02/19 07:12:49 -8:00

Notary Public

Notary ID Number: __2019-RE-775042_____

My Commission Expires: __April 29, 2024___

B6C97785-0E13-4DA1-A3A9-AA855206CDAA --- 2021/02/19 03:53:47 -8:00 --- Remote Notary

VERIFICATION

The undersigned, Brian K. West, being duly sworn, deposes and says he is Vice President, Regulatory & Finance for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Brian K. West

State of Indiana)
) ss Case No. 2020-00174
County of Allen)

Subscribed and sworn to before me, a Notary Public, in and for said County and State, Brian K. West this 17th day of February, 2021.

Regiana M. Sistevaris

Digitally signed by Regiana M. Sistevaris
Date: 2021.02.17 13:03:35 -05'00'

Regiana M. Sistevaris, Notary Public

My Commission Expires: January 7, 2023